BROADWATER

RESOURCE REPORT NO. 1

GENERAL PROJECT DESCRIPTION

FOR A

PROJECT TO CONSTRUCT AND OPERATE A

LIQUEFIED NATURAL GAS RECEIVING TERMINAL

IN

LONG ISLAND SOUND

LONG ISLAND, NEW YORK

UNITED STATES OF AMERICA

JANUARY 2006

PUBLIC

BW000636

RESOURCE REPORT 1 – GENERAL PROJECT DESCRIPTION

Minimum Filing Requirement	Location in Environmental Report
• • Provide a detailed description and location map of the project facilities. (§ 380.12 (c) (1)).	Section 1.1, Figure 1-1
• • Describe any nonjurisdictional facilities that would be built in association with the project. (§ 380.12 (c) (2)).	N/A
• • Provide current original U.S. Geological Survey (USGS) 7.5-minute-series topographic maps with mileposts showing the project facilities. (§ 380.12 (c) (3)).	Section 1.3.3, Figures 1-9, Part 1 and Part 2
• • Provide aerial images or photographs or alignment sheets based on these sources with mileposts showing the project facilities. (§ 380.12 (c) (3)).	Section 1.3.3, Figures 1-9, Part 1 and Part 2
• • Provide plot/site plans of compressor stations showing the location of the nearest noise-sensitive areas (NSA) within 1 mile. (§ 380.12 (c) (3, 4)).	N/A
• • Describe construction and restoration methods. (§ 380.12 (c) (6)).	Section 1.5
• • Identify the permits required for construction across surface waters. (§ 380.12 (c) (9)).	Section 1.9
• • Provide the names and addresses of all affected landowners and certify that all affected landowners will be notified as required in § 157.6(d). (§§ 380.12(a)(4) and (c)(10)).• •	N/A

Environmental Information Request
July 12, 2005

Request	Location in Environmental Report
1. Section 1.2 provides information on the supply and demand for natural gas at the national and "regional" (the states of New York and Connecticut) levels. Provide current and more detailed information on the specific supply and demand for natural gas in the target market areas for the Broadwater project.	Sections 1.2.2.1 and 1.2.2.2
2. Indicate the average daily volume of gas that would be transported to the south from the project (i.e., to Long Island and areas south of Long Island served by IGTS) and the volume of gas that would be transported to the north from the project (i.e., to Connecticut and other areas north of Long Island Sound served by IGTS).	Section 1.2.2.5
3. Provide the number of workers anticipated for each major construction activity, including the peak workforce and the duration of the peak workforce.	Sections 1.5.2.2 and 1.5.3.11
4. Describe any onshore facilities that would be required for construction and operation of the proposed project. Identify the land requirements for any such facilities.	Sections 1.5.4 and 1.6.4
Floating Storage and Regasification Unit (FSRU)	
5. Section 1.1 states the deck of the FSRU would be approximately 80 feet above the water line. Clarify whether this value represents the maximal exposure under the range of operating conditions.	Section 1.1
6. Provide additional information on the design and basic components of the FSRU, including at least the following: • Hull design (single or double). • Number and size of individual storage tanks. • Composition of the primary barrier, insulation, and secondary barrier. Identify the major equipment and structures that would be on the deck and provide the dimensions, including the height that these items would extend above the deck.	Section 1.3.2

Request	Location in Environmental Report
7. Indicate how many shell and tube vaporizer (STV) units would be present on the FSRU and provide information on the design and operation of these units, including the medium used to heat the LNG, the power source for heating the medium, and the discharges and emissions associated with use of this technology.	Section 1.3.2.3
8. Indicate whether or not a flare stack would be installed and, if so, the height of the stack and information on the anticipated flaring requirements.	Section 1.3.2.3
Mooring Tower	
9. Revise Figure 1-2 to accurately depict a connection between the pipeline and the transfer lines attached to the mooring tower.	Section 1.3, Figure 1-7
10. Provide additional information on the mooring tower, mooring head, and yoke, including at least the following:	Section 1.3.2.4
• Diameter of the legs. • Distance between the legs. • Method used to attach the legs to the piles. • Dimensions of the portion of the tower above sea level and the height above sea level. • Information on the counterweight that would be included with the structure.	
• Maintenance procedures that would be used on the tower, both above and under the water.	Section 1.6.2
11. Indicate whether the entire tower and yoke mooring system would be installed in place or if portions would be constructed elsewhere, towed to the site, and installed. If portions would be constructed elsewhere, identify the planned location of pre-assembly and the associated land requirements.	Section 1.5.2
12. Provide information on the LNG transfer system that would be used, including the diameter, length, and composition of the LNG transfer lines. State the wall thickness and composition of the send-out pipeline.	Section 1.3.2.4 Section 1.3.3.3

Request	Location in Environmental Report
13. Describe the construction methods that would be used to drive the piles and install the mooring tower and the yoke mooring system. Identify the types of vessels (e.g., barges and support vessels) that would be used and how station-keeping would be accomplished (e.g., anchoring or dynamically positioned); the timing, sequencing, and duration of pile driving and construction activities (e.g., start and end dates and daily construction hours); the number of workers required; and the sea floor footprint needed for construction and operation.	Section 1.5.2
Pipeline	
14. Clarify whether or not mainline block valves would be constructed in association with the project. If they would be included in the project, identify the locations of the valves and describe how they would be controlled and monitored.	Section 1.3.3.6
15. Provide an illustration of and/or additional information on the split tee mechanical connection that would be used to connect to the project's subsea connecting pipeline to the existing IGTS pipeline, including portions of the connection, if any, that would extend above the sea floor. Describe the construction technique that would be used to install the hot tap connection to the IGTS pipeline.	Section 1.3.3.6, Figure 1-12 Section 1.5.3.5

Request	Location in Environmental Report
16. Provide additional information on pipeline installation, including at least the following:	
• Specific procedures, construction methods, and the total construction footprint associated with trenching and installation of the pipeline.	Section 1.5.3.3
• Identify the types of vessels (e.g., lay barges and support vessels) that would be used and how station-keeping would be accomplished (e.g., anchoring or dynamically positioned).	Sections 1.5.3.2 and 1.5.3.9
• Identify the timing and duration of pipeline construction activities.	Section 1.5.3.10
• List the width, length, and area of the spoil piles that would be located adjacent to the pipeline trench. If the piles would be used to backfill the trench, indicate the length of time between trenching and backfilling and the measures that would be used to ensure the stability of the spoil piles.	Sections 1.5.3.3 and 1.5.3.7
If a conventional anchored lay barge would be used to accomplish pipeline installation, provide additional information on anticipated anchor spreads (e.g., extent within or beyond the construction right-of-way), anchor movement procedures, number of anchor movements, and anticipated benthic effects (e.g., area affected by each anchor movement).	Section 1.5.3.3.1
Also identify any monitoring procedures that would be implemented to ensure proper anchor placement and to detect any unanticipated anchor movement.	Section 1.5.3.2

Request	Location in Environmental Report
17. For hydrostatic testing, provide at least the following information: • Anticipated volumes, intake and discharge locations, and disposition of all hydrostatic test water. • Method used to filter seawater prior to transfer into the pipeline. • Method used to remove construction debris ahead of cleaning pigs. • Water quality testing procedures used prior to discharge of the hydrostatic test water. If a biocide is used, specifics on its toxicity towards resident aquatic biota, treatment procedures, and discharge/disposal alternatives to be considered.	Section 1.5.3.8
Operation	
18. Clarify how boil off gas not routed to the LNG carriers would be handled. Also clarify whether the boil off gas compressors mentioned in Section 1.3.1.3.2 are the same as the re-condensers, which are also mentioned in that section.	Section 1.3.2.3
19. Section 1.3.1.3.3 states that LNG from the tanks passes through a re-condenser. Clarify whether or not condensed boil off gas would be introduced into the LNG stream.	Section 1.3.2.3
20. Describe the "super heater" and “process heaters” mentioned in Section 1.3.1.3.3, including the sources of power, type of fuel, fuel storage capacities and containment structures, heating equipment, and basic information on emission control technology to be used (including, if appropriate, information on delivery and storage of ammonia compounds that may be used for emission control if SCR technology is used).	Sections 1.3.2.3, 1.3.2.5.3, and 1.3.2.8.2
21. Indicate the volume of fuels (e.g., diesel or fuel oil) and lubricants to be stored onboard, indicate where these materials would be stored, and describe the proposed containment facilities and spill handling procedures.	Section 1.3.2.5.4

Request	Location in Environmental Report
22. Regarding LNG delivery and transfer, provide information on the anticipated transit duration and timing, transit routes (through federal and state waters), and berthing and offloading times of the LNG carriers.	Section 1.6.1
23. Provide additional information on the ballast water intake and discharge system of the FSRU and the LNG carriers, including information on the design of screens to be installed at the intake facilities, the depths of the intake facilities, and the anticipated flow rate and volumes at each intake facility. Provide similar information for the cooling water intakes for the FSRU (if any) and the LNG carriers. In addition, assess the feasibility of providing a ballast system that would allow transfer of ballast water between the FSRU and the LNG carriers during LNG transfer operations to minimize total ballast water intake.	Section 1.3.2.8.1 See Resource Report 10 (Alternatives)
24. In Section 1.3.1.6, it is not clear why ballast flow rates of the FSRU are based on the loading rates of an LNG carrier. Provide ballast water intake flow rates of the LNG carriers during off-loading, and the ballast water intake flow rates of the FSRU during vaporization and discharge of natural gas from the FSRU.	Section 1.3.2.8.1
25. For the seawater system described in Section 1.3.1.7.1, provide a list of all effluents and wastes from the desalination unit, describe what over-side sprays would be used for hull protection during cargo transfer operations, indicate the total volume of seawater intake expected to be associated with the seawater system, and describe the depth and design of the intake facilities (including the intake screen design) for the seawater system (if it is separate from the ballast water system).	See Resource Report 2 (Water Use and Quality)

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26. In Section 1.3.1.7.1, state which regulatory requirements apply to the temperature and constituents of seawater discharges from the project.	See Resource Report 2 (Water Use and Quality)
27. In Section 1.3.1.7.2, provide the maximum flow rates and discharge locations for either the selected wastewater treatment system or if the system has not been selected, for each of the treatment options being considered.	Section 1.3.2.8.2
28. Describe the storage and handling procedures that would be used for the odorant used for the natural gas.	Section 1.3.2.8.2
29. In Section 1.3.1.9.2, provide information on operation of the command and control systems, including at least the leak detection and spill detection systems, vessel controls, visual observation of the safety zone and reporting requirements, communications with the support vessels, and communications with the LNG carriers.	See Resource Report 11 (Safety and Reliability)
30. Provide additional information on the pig launching and receiving traps and the associated containment facilities, including a description of how the subsea receiving trap would be operated. Also clarify how pig retrieval would be accomplished during operation since only a "temporary" trap would be installed near the IGTS interconnect.	Section 1.5.3.8 Section 1.6.3

Environmental Information Request
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Request	Location in Environmental Report
1. Provide the New York – Connecticut state line on Figure 1-1, and label all of the key equipment depicted on Figure 1-2.	Figures revised
2. Provide the following information for the floating storage and regasification unit (FSRU) and the mooring tower and yoke mooring structure (YMS):	
a. the likely location of the shipyard where the FSRU would be constructed, or if a single location cannot be identified at this time, list the options that would be considered;	Section 1.3.2.1
b. the likely location of the shipyard or other facility where the mooring tower and YMS would be constructed, or if a single location cannot be identified at this time, list the options that would be considered (*July 12 Request No. 11*);	Section 1.3.2.1
c. if a shipyard or shipyards in the U.S. would be used for the Project, indicate whether or not major changes to the structure and operation of the shipyards would be required to construct the FSRU or mooring system; and	Section 1.3.2.1
d. the procedures used to grout the mooring tower to the piles and the composition of the grout, including toxicity information (*July 12 Request No. 10*).	Section 1.5.2.2
3. Provide the following information on the onshore facilities and operations *(July 12 Request No. 4)*:	
a. the location and size of each pipeyard, concrete coating facility, warehouse, and office support facility that would be used for the Project; if specific locations cannot be identified at this time, list the options that would be considered; and	Section 1.5.4 for temporary facilities Onshore Facilities Resource Report
b. descriptions of the activities that would be conducted at onshore facilities during construction and operation of the Project.	Section 1.5.4 and 1.6.3 Onshore Facilities Resource Report

Request	Location in Environmental Report
4. Provide the following information regarding the purpose-built tugs:	
a. the number of tugs that would have to be built to meet the needs of the Project;	Section 1.6.1
b. the likely location of the shipyard where the tugs would be constructed, or if a single location cannot be identified at this time, provide a list of options;	Section 1.6.1
c. if a shipyard or shipyards in the U.S. would be used for the tugs, indicate whether or not major changes to the structure and operation of the shipyards would be required to construct the tugs; and	Section 1.6.1
d. the port where permanent mooring would be provided, or if a single location cannot be identified at this time, provide a list of options.	Section 1.6.1
5. Provide the following information regarding the LNG carriers that Broadwater anticipates using to provide the LNG:	
a. the volume and maximum flow velocity of ballast water intake and the mesh size of the intake screens; and	Section 1.3.2.12
b. the volume, maximum flow rate, and chemical constituents of the LNG carrier's "water curtain" used during unloading.	Section 1.6.3
6. Section 1.3.2.4 states that the mooring system would be designed to withstand "extreme" storms. State what the design-level storm is for this facility (*July 12 Request No. 5*).	Section 1.3.2.4
7. Clarify what is meant by "inhibited fresh water" in the last paragraph on Page 1-25.	Section 1.3.2.4
8. Provide the following information on water discharge systems:	
a. descriptions of the water treatment plant options being considered for use on the FSRU (*July 12 Request No. 27*);	Section 1.3.2.8.2
b. the amount, flow rate, and discharge locations for treated wastewater if a treatment system would be used (*July 12 Request No. 27*); and	Section 1.3.2.8.2

Request	Location in Environmental Report
c. Best Management Practices and other measures for ensuring that discharged stormwater meets state standards for constituents and temperature.	Section 1.3.2.9
9. Identify the locations where spilled LNG would be directed overboard and describe how the spill discharge system has been designed to avoid cryogenic damage to the hull and other structures of the FSRU, the LNG carriers, and support vessels.	Section 1.3.2.11.2
10. How would the mainline block valves be controlled and monitored? *(July 12 Request No. 14*).	Section 1.3.3.6
11. Section 1.3.3.8 indicates that "protective structures" may be placed over the interconnection sites of the proposed pipeline with the FSRU and with the IGTS pipeline. Describe these structures and how they will be placed, including information such as size, composition, and how deeply the structures would be buried (*July 12 Request No. 15*).	Section 1.3.3.8
12. Section 1.3.3.9 states that Broadwater will "manage send-out gas properties." Describe the procedures and equipment that will be used to accomplish this.	Section 1.3.3.9
13. Section 1.5.1 states that the FSRU would exchange ballast prior to entering Long Island Sound. State approximately where this would be accomplished (distance from U.S. waters), how many exchanges of ballast water would be made, and what specific requirements would be followed.	Section 1.3.2.8.1
14. Section 1.5.2.2 provides information on the construction workforce for installation of the mooring tower. State how many of the workforce would be housed on offshore vessels for the duration of installation or how many would require onshore living accommodations.	Section 1.5.2.2

Request	Location in Environmental Report
15. Other Resource Reports have indicated that a "mud mat" would be in place beneath the mooring tower during installation. There is no reference to a mud mat in Section 1.5.2.2. If a mud mat is to be included in the installation procedures, provide information on its size, composition, and use.	Section 1.5.2.2
16. Provide a draft of the anchoring plan and state the maximum distance from the centerline of the pipeline to anchor locations during construction (*July 12 Request No. 16*).	Section 1.5.3.2
17. Specify the regulatory basis for the following:	
a. a 300-foot-wide pipeline construction corridor, and identify how it relates to the "central construction corridor" that is referred to in other resource reports; and	Section 1.4.1
b. a 50-foot-wide permanent ROW.	Section 1.4.1
18. Provide a detailed description of the specialized trenching activities at the FSRU and the IGTS interconnection, including specific excavation methods, geographic extent by milepost, spoil handling, backfilling (including a description of "mechanically backfilling" the 2 miles of trench adjacent to the mooring tower), and measures to avoid and minimize potential impacts during construction. Also, provide an estimate of the time between trenching and completion of natural backfilling of the trench (*July 12 Request No. 16*).	Section 1.5.3.7
19. Section 1.6.3 states that a "pollution dome" would be used during pigging recovery operations. Describe this equipment, how it would be used, what, if any materials it might capture, and how those materials would be transported to the surface and disposed of (*July 12 Request No. 30*).	Section 1.6.4

Request	Location in Environmental Report
20. In Section 1.6, provide information on the maintenance activities that would be conducted for the FSRU and mooring system that could have an adverse environmental effect. This information should include a description of the above- or below-sea maintenance activities that would be used on the outer portions of the FSRU and on the mooring tower, including information on the toxicity of any chemicals, solvents, paints, or other substances used as a part of maintenance procedures (*July 12 Request No. 10*).	Section 1.6.2
21. Describe the environmental compliance monitoring/inspection procedures that would be conducted during construction and operation, including mitigation monitoring procedures for all relevant environmental concerns, particularly for turbidity and sedimentation.	Section 1.5.3.3.5
22. Provide contingency plans that describe the methods, impacts, and measures to avoid and minimize impacts associated with the following:	
a. drilling during pile installation;	Section 1.5.2.2
b. dredging at Stratford Shoal;	Appendix C
c. protecting the subsea pipeline if a minimum of 3-foot burial depth is not feasible; and	Section 1.5.3.6
d. the central cooling water backup system including expected frequency and duration of use.	Section 1.6.3
23. Section 1.6.1 states that the loading arms would be drained before disconnection. Describe where the LNG in the loading arms would be directed and how it would be directed back into the LNG storage system.	Section 1.6.1
24. Section 1.6.3 states that the metering station on the FSRU would serve as a part of the safety and leak detection systems for the pipeline. Provide additional information on how data from the metering station would assist in detecting leaks from the pipeline.	Section 1.6.3

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Request	Location in Environmental Report
25. Describe where gas in the proposed pipeline would be directed in the event it is necessary to evacuate the pipeline and the IGTS pipeline is not available for use.	Section 1.3.3.6

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APPENDIX

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List of Acronyms and Abbreviations

ABS	American Bureau of Shipping
AEO	Annual Energy Outlook
AGA	American Gas Association
AHT	anchor handling tug
ANSI	American National Standards Institute
API	American Petroleum Institute
ASME	American Society of Mechanical Engineers
AT&T	American Telephone and Telegraph Company
bcf	billion cubic feet
bcfd	billion cubic feet per day
BOG	boil off gas
Btu	British thermal units
CEAB	Connecticut Energy Advisory Board
CFR	Code of Federal Regulations
CO	carbon monoxide
CSC	Cross Sound Cable
CWA	Clean Water Act
DC	direct current
°C	degrees Celsius
°F	degrees Fahrenheit
DGPS	Differential Global Positioning System
DO	dissolved oxygen
DOC	(United States) Department of Commerce
DP	dynamically positioned
DPDSV	dynamically positioned dive support vessel
DSV	dive support vessel
EEA	Energy and Environmental Analysis, Inc.
EIA	Energy Information Administration
EPA	(United States) Environmental Protection Agency
ESD	emergency shutdown
ESDS	emergency shutdown system
FERC	Federal Energy Regulatory Commission
FSRU	floating storage and regasification unit
fsw	water depth in feet
GPS	Global Positioning System
IGTS	Iroquois Gas Transmission System
INS	Immigration and Naturalization Service
ISA	Instrument Society of America
ISO	International Standards Organization
km	kilometer
LNG	liquefied natural gas
m	meter
m^2	square meter

m^3	cubic meter
MAOP	maximum allowable operating pressure
mcf	thousand cubic feet
mg/L	milligrams per liter
mmcfd	million cubic feet per day
MP	milepost (along subsea connecting pipeline)
MPN	Most Probable Number
MSS	mooring support structure; also Manufacturers Standardization Society of the Valve and Fitting Industry
MW	megawatt
NACE	National Association of Corrosion Engineers
NEEC	Northeast U.S. and Eastern Canada
NEPA	National Environmental Policy Act
NOAA	National Oceanic and Atmospheric Administration
NO_x	nitrogen oxides
NYISO	New York Independent System Operator
NYS	New York State
NYSDEC	New York State Department of Environmental Conservation
NYSDOS	New York State Department of State
NYSDPS	New York State Department of Public Service
NYSERDA	New York State Energy Research and Development Agency
NYSOGS	New York State Office of General Services
NYSOPRHP	New York State Office of Parks Recreation and Historic Preservation
OCIMF	Oil Companies International Marine Forum
OSHA	Occupational Safety and Health Administration
PAHs	polycyclic aromatic hydrocarbons
PCHE	printed circuit heat exchanger
ppm	parts per million
ppt	parts per thousand
psi	pounds per square inch
RTJ	ring type joint
SCADA	supervisory control and data acquisition
SCR	selective catalytic reduction
SPCC	Spill Prevention Control and Countermeasures
SPDES	State Pollutant Discharge Elimination System
SSSV	subsea-subsurface safety valve
STV	shell and tube vaporizer
tcf	trillion cubic feet
tonne	metric ton (equal to 1,000 kg or 2,204 pounds)
UBC	Uniform Building Code
USACE	United States Army Corps of Engineers
USCG	United States Coast Guard
USDOE	United States Department of Energy
USDOT	United States Department of Transportation
USDOT OPS	United States Department of Transportation Office of Pipeline Safety
USFWS	United States Fish and Wildlife Service

USGS	United States Geological Survey
VOCs	volatile organic compounds
WHRU	waste heat recovery unit
YMS	yoke mooring system

1. GENERAL PROJECT DESCRIPTION

1.1 INTRODUCTION

Broadwater Energy, a joint venture between TCPL USA LNG, Inc., and Shell Broadwater Holdings LLC, is filing an application with the Federal Energy Regulatory Commission (FERC) seeking all of the necessary authorizations pursuant to the Natural Gas Act to construct and operate a marine liquefied natural gas (LNG) terminal and subsea connecting pipeline for the importation, storage, regasification, and transportation of natural gas. The Broadwater LNG Project (the Project) will increase the availability of natural gas to the New York and Connecticut markets through an interconnection with the Iroquois Gas Transmission System (IGTS). The FERC application for the Project requires the submittal of 13 Resource Reports, with each report evaluating project effects on a particular aspect of the environment.

Resource Report 1 describes the proposed Project facilities, the purpose and need for the Project, and land requirements for the proposed facilities. Proposed construction procedures, operation and maintenance plans, and the reasonably foreseeable plans for potential future expansion and abandonment of the Project are also described. This Resource Report also lists the various environmental permits and approvals required to construct and operate the Project, describes non-jurisdictional facilities related to the Project, and identifies the landowners whose property will be involved in the Project.

The proposed Broadwater LNG terminal will be located in Long Island Sound (the Sound), approximately 9 miles (14.5 kilometers [km]) from the shore of Long Island in New York State waters, as shown on Figure 1-1. The LNG terminal facilitates the sea-to-land transfer of natural gas. It will be designed to receive, store, and regasify LNG at an average throughput of 1.0 billion cubic feet per day (bcfd) and will be capable of delivering a peak throughput of 1.25 bcfd. The Project will deliver the regasified LNG to the existing interstate natural gas pipeline system via an interconnection to the IGTS pipeline. Onshore facilities are discussed in Onshore Facilities Resource Reports.

The proposed LNG terminal will consist of a floating storage and regasification unit (FSRU) that is approximately 1,215 feet (370 meters [m]) in length, 200 feet (60 m) in width, and rising approximately 80 feet (25 m) above the water line to the trunk deck, as shown on Figure 1-2. The FSRU's draft is approximately 40 feet (12 m). The freeboard and mean draft of the FSRU will generally not vary throughout operating conditions. This is achieved by ballast control to maintain the FSRU's trim, stability, and draft. The FSRU will be designed with a net storage capacity of approximately 350,000 cubic meters [m^3] of LNG (equivalent to 8 billion cubic feet [bcf] of natural gas) with base vaporization capabilities of 1.0 bcfd using a closed-loop shell and tube vaporization (STV) system. The LNG will be delivered to the FSRU in LNG carriers with cargo capacities ranging from approximately 125,000 m^3 up to a potential future size of 250,000 m^3 at the frequency of two to three carriers per week.

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Source: ESRI StreetMap, 2002.

Figure 1-1
Proposed Broadwater Project
Location in Long Island Sound


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BROADWATER - FSRU
BROADWATER

The FSRU will be connected to the send-out pipeline, which rises from the seabed and is supported by a stationary tower structure. In addition to supporting the pipeline, the stationary tower also serves the purpose of securing the FSRU in such a manner to allow it to orient in response to prevailing wind, wave, and current conditions (i.e., weathervane) around the tower. The tower, which is secured to the seabed by four legs, will house the yoke mooring system (YMS) allowing the FSRU to weathervane around the tower. The total area under the tower structure, which is of open design, will be approximately 13,180 square feet (1,225 square meters [m^2]).

A 30-inch-diameter natural gas pipeline will deliver the vaporized natural gas to the existing IGTS pipeline. It will be installed beneath the seafloor from the stationary tower structure to an interconnection location at the existing 24-inch-diameter subsea section of the IGTS pipeline, approximately 22 miles (35 km) west of the proposed FSRU site. To stabilize and protect the operating components, sections of the pipeline will be covered with engineered back-fill material or spoil removed during the lowering operation. Figure 1-1 presents the proposed pipeline route.

1.2 PURPOSE AND NEED

1.2.1 Purpose

Based on historical trends and future projections, the Long Island, New York City, New York City metropolitan area, and Connecticut markets (the Region) are expected to face a projected critical period over the next 10 to 15 years in meeting the anticipated energy needs of consumers. The Project will provide a source of reliable, long-term, and competitively priced natural gas to the Region to meet this growing demand. To fulfill this purpose and need, a viable LNG import terminal site must meet, at a minimum, the following specific criteria:

- Be technically and economically feasible, practicable, and implementable;
- Maximize the buffer between the Project and populated areas;
- Have significant environmental benefits over other alternatives;
- Be able to provide reliable natural gas deliveries to the Region via pipeline connections while maximizing deliverability to New York City and Long Island;
- Provide deepwater berthing to accommodate LNG carriers up to a potential future size of 250,000 m^3 capacity;
- Provide for storage and vaporization facilities for at least 1.0 bcfd of natural gas, with an in-service date of 2010;
- Comprise a site that allows the terminal to maintain sufficient control and proprietary rights of operation;

- Comprise a site situated close to an existing pipeline system serving the Region with downstream takeaway capability greater than 1.0 bcfd; and

- Be able to ensure facility and interconnecting pipeline operability for a minimum 30-year project life.

1.2.2 Need

This section summarizes the need for the Project based on current and future trends of domestic natural gas supply, demand, and costs.

1.2.2.1 Natural Gas Demand

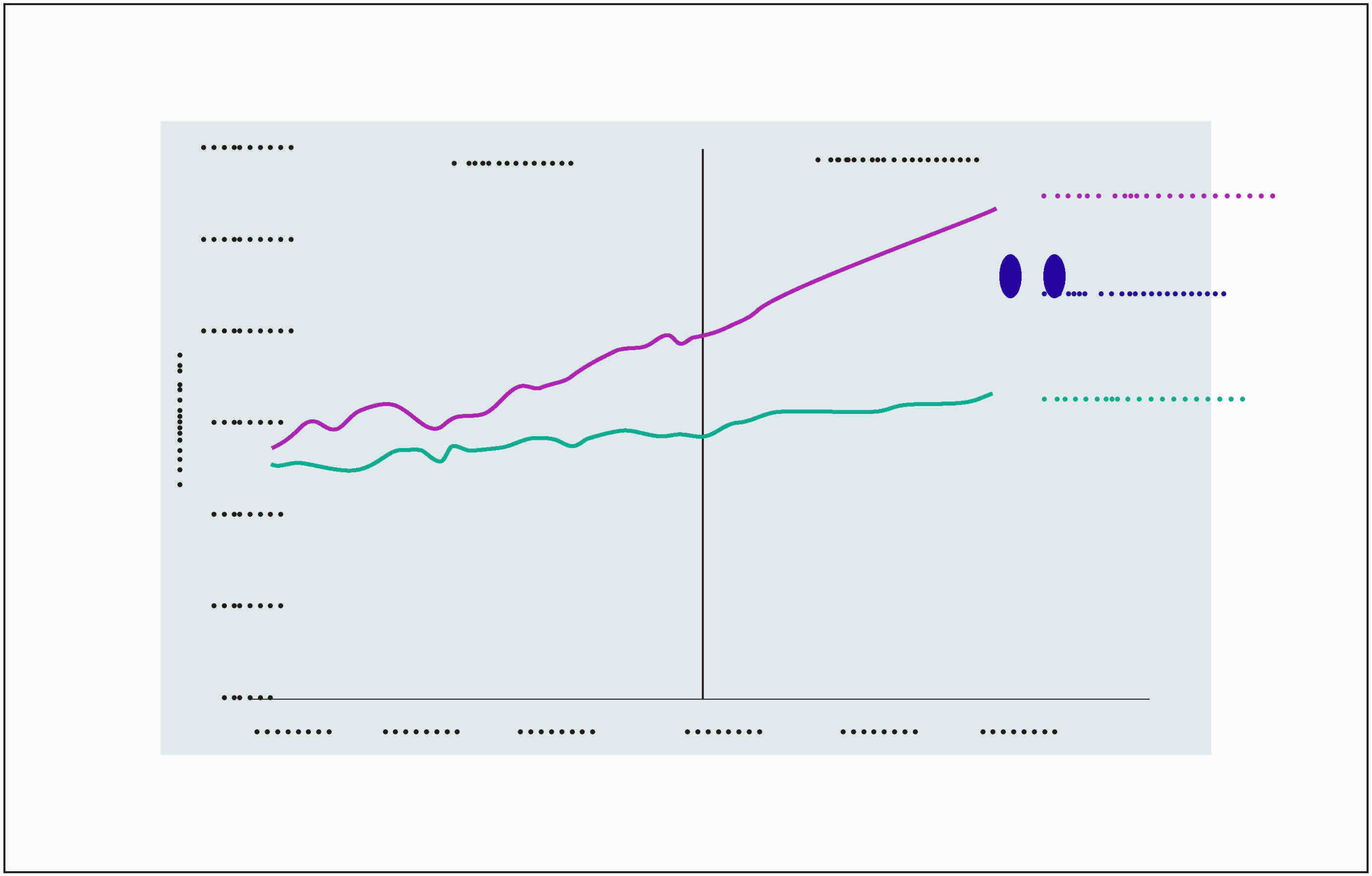
Total energy demand in the U.S. is projected to increase at an average annual rate of 1.4% from 2003 to 2025 according to the U.S. Department of Energy (USDOE), Energy Information Administration's (EIA's) *Annual Energy Outlook 2005* (*AEO 2005*) (EIA 2005a, page 3). This will result in an increase in total primary energy consumption within the U.S. from 98.2 quadrillion British thermal units (Btu) in 2003 to 133.2 quadrillion Btu by 2025 (*see* Figure 1-3).

With respect to natural gas, the EIA projects that demand within the U.S. will increase at an average annual rate of 1.5% through 2025. Nearly 75% of this increase is attributed to gas-fired power generating facilities and other industrial applications (EIA 2005a, page 4).

The projected increase in national demand for natural gas is outpaced by the projected requirements of New York. Natural gas demand within New York is expected to grow nearly 37% by 2021 from its current levels, with nearly 61% of this increase due to natural gas demand for electrical power generation (NYSERDA 2002, page 3-9). Of this amount, nearly 70% is projected for use in the area from Rockland and Orange Counties through Long Island (NYSERDA 2002, page 3-159).

As part of its assessment of the need for the Project, Broadwater commissioned an independent assessment of the northeast U.S. and eastern Canada natural gas markets. This study, completed by Energy and Environmental Analysis, Inc. (EEA), is provided as Appendix A. In addition to the broader regional demand picture, the study also examined natural gas market growth in the New York City, Long Island, and southern Connecticut regions, which are adjacent to the proposed site of the Project. The conclusions of the study are as follows:

> Within the U.S. and Canada, the Northeast U.S. and Eastern Canada [NEEC] are among the most attractive for LNG imports. The area currently accounts for 14 percent of the total gas use in the U.S. and Canada with over 3.5 tcf annual consumption, and like the rest of North America, the area's gas consumption for power generation is likely to



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> grow significantly in the foreseeable future. The area's total gas consumption is expected to grow by 1.5 percent annually, with total annual consumption reaching nearly 5 tcf by 2015.
>
> Current gas consumption in New York City, Long Island and Southern Connecticut, markets that would be directly connected to Broadwater, is approximately 700 bcf per year, or just under one-fifth of the total NEEC market. Recent market growth has averaged 2.7 percent per year. Similar to the region as a whole, most of the growth in gas consumption in this area has been driven by the power generation sector. In the past ten years, annual power sector gas consumption has increased by 100 bcf. Annual growth rate in the power sector have (*sic*) averaged 5.6 percent.
>
> In an environment of increasing gas consumption, LNG imports will become an important source of gas supply for the area's consumers. Consumers would benefit in a number of ways from a new Broadwater facility. First, LNG supplies are a needed diversification to the supplies that originate in Western Canada and the Gulf Coast. Currently, Western Canada and [the] Gulf Coast supply 85 percent of the gas consumed in the area. LNG imports at Broadwater and other NEEC locations could potentially reduce that level to 60 percent. A Broadwater facility may reduce the need for future long-haul transportation that has proven difficult to build into the New York and New England markets.

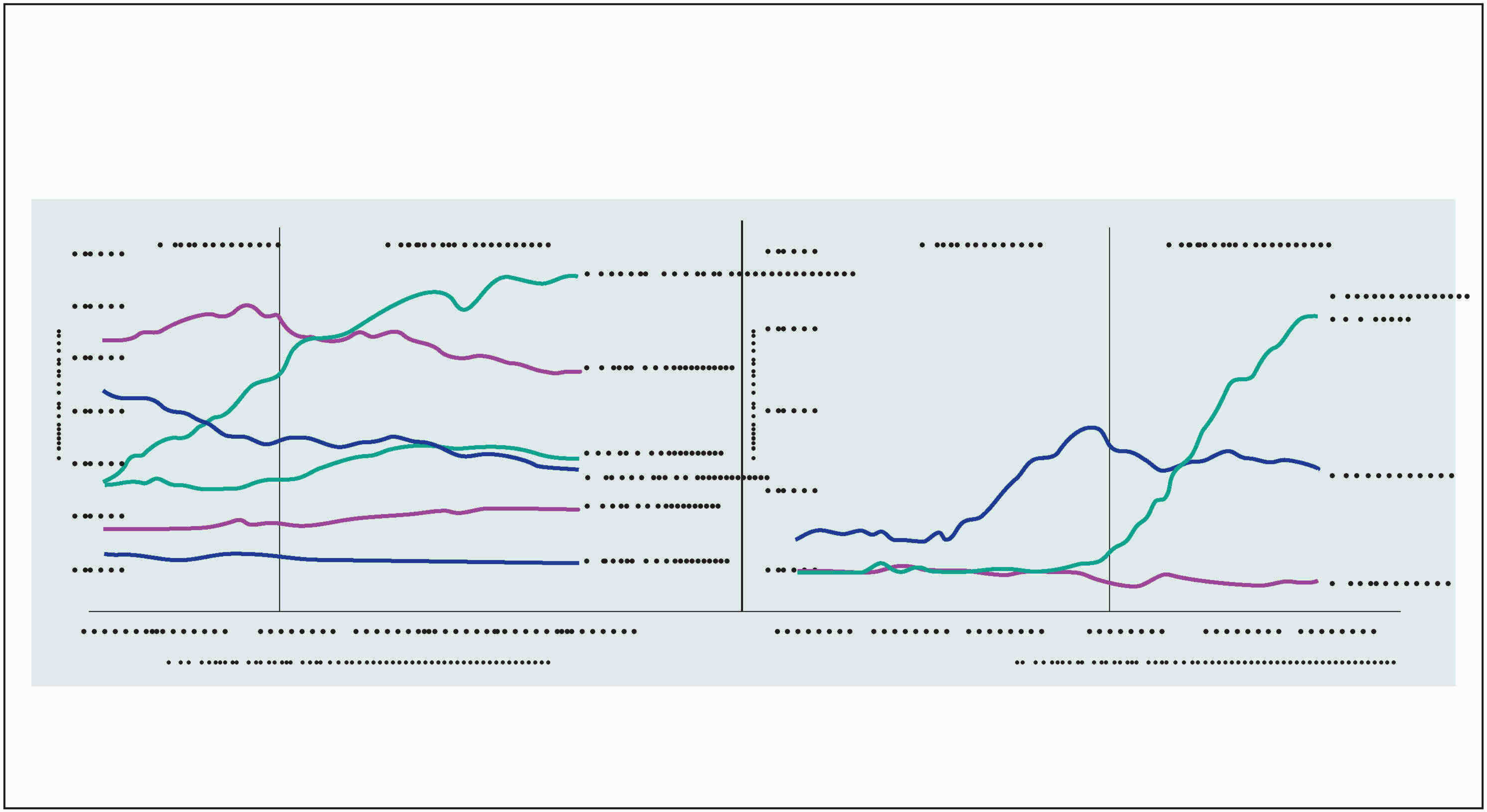
(S*ee* EEA Report in Appendix A).

1.2.2.2 Natural Gas Supply

The natural gas supply for the U.S. currently comes from three sources: domestic production, imports from Canada, and a relatively small amount of LNG imports from overseas sources (*see* Figure 1-4).

Domestic production of natural gas has remained relatively flat over the past several years, and projected increases in production will not keep pace with projected demand. The *AEO 2005* (EIA 2005a) indicates total energy consumption is expected to increase more rapidly than domestic energy supply through 2025. Figure 1-3 presents a graph depicting total energy consumption and production for the years 1970 through 2025. To offset this imbalance, net imports of energy are expected to constitute 38% of the total U.S. energy use by 2025 (EIA 2005a, page 7).

Specifically, domestic onshore production of natural gas is projected to increase from 13.9 trillion cubic feet (tcf) in 2003 to 15.7 tcf in 2012, and then decline to 14.7 tcf by 2025 (EIA 2005a, page 7). This limited increase in supply is attributed to slow growth in gas reserves, fewer new discoveries, and higher exploration and development costs (EIA 2005a, page 7). Domestic offshore production of natural gas is projected to increase from its current level of 4.7 tcf to nearly 5.3 tcf by 2014, and then decline to 4.9 tcf by 2025 (EIA 2005a, page 7). Anticipated trends are presented on Figure 1-4.



Imported Canadian supplies of natural gas are projected to decline from their current level of nearly 3.1 tcf to approximately 2.5 tcf by 2009 (EIA 2005a, page 7). However, from 2010 to 2015 supplies of Canadian natural gas are projected to increase to nearly 3.0 tcf due to higher anticipated natural gas prices, the introduction of additional natural gas from the Mackenzie Delta region, and increased coal bed methane production (EIA 2005a, page 7). By 2025, the U.S. importation of Canadian supplies is again projected to decrease to approximately 2.6 tcf in response to reserve depletion and a growing Canadian domestic market (EIA 2005a, page 7) (*see* Figure 1-4).

The natural gas supply for the Northeast U.S. is dependent upon major interstate and intrastate pipeline systems for access to domestic and imported Canadian gas supplies (NYSERDA 2002). Domestic natural gas accounts for approximately 62% of the natural gas supplied to the New York region, with nearly all of the remainder coming from Canadian sources (NYSERDA 2002, page 3-153). Although natural gas production within New York State is increasing, this supply accounts for only 2% of the natural gas consumed annually in the state (NYSERDA 2002, page 3-153).

In summary, the projected growth in U.S. natural gas supplies will depend on unconventional domestic production, natural gas from Alaska, and imports of LNG (EIA 2005a, page 8) with the net import of natural gas making up the difference between projected U.S. production and consumption. All forecasts show domestic production providing a decreasing share of total natural gas supply.

1.2.2.3 Natural Gas Prices

On a regional basis, natural gas commodity prices in the New York and Connecticut region have shown a clear tendency towards both an increase in the average price level and increasing price volatility or variation around the average price level.

As Table 1-1 shows, New York City gate prices averaged $2.93 per thousand cubic feet (mcf) over the five-year period from 1995 to 1999. Over the next three years (2000-2002), New York City gate prices averaged $4.37 per mcf, an increase of 49%. Over the last two years (2003-2004), average price levels have increased an additional 35%. A similar situation has unfolded in Connecticut.

Table 1-1 Historical New York City and Connecticut Gas Prices

	1995 – 1999 Period	2000 – 2002 Period	Jan 2003 to Jun 2005 Period
New York City Gas Price	2.93	4.37	6.14
Connecticut Gas Price	4.97	7.15	6.84

(all values in dollars per thousand cubic feet)

Monthly gas price data from Energy Information Administration (EIA 2005b).

In addition to the increasing price level of natural gas in the region, volatility of natural gas prices has also increased. Figure 1-5 presents the monthly city gate prices for New York City and Connecticut from January 1995 to June 2005 (EIA 2005b). The increasing variation in natural gas prices, particularly in the winter months, is apparent. There are a number of reasons for this increasing volatility. First, the growth in natural gas transportation serving the Region has not kept pace with growing demand. Furthermore, gas markets in the New York City and New England areas are closely connected because of New England's reliance on pipeline flows on the Algonquin Gas Transmission and Tennessee Gas Pipeline systems coming through the New York City and Connecticut area. The pipeline linkage between the two areas causes gas prices in the two regions to be tightly linked and to react to events in either market.

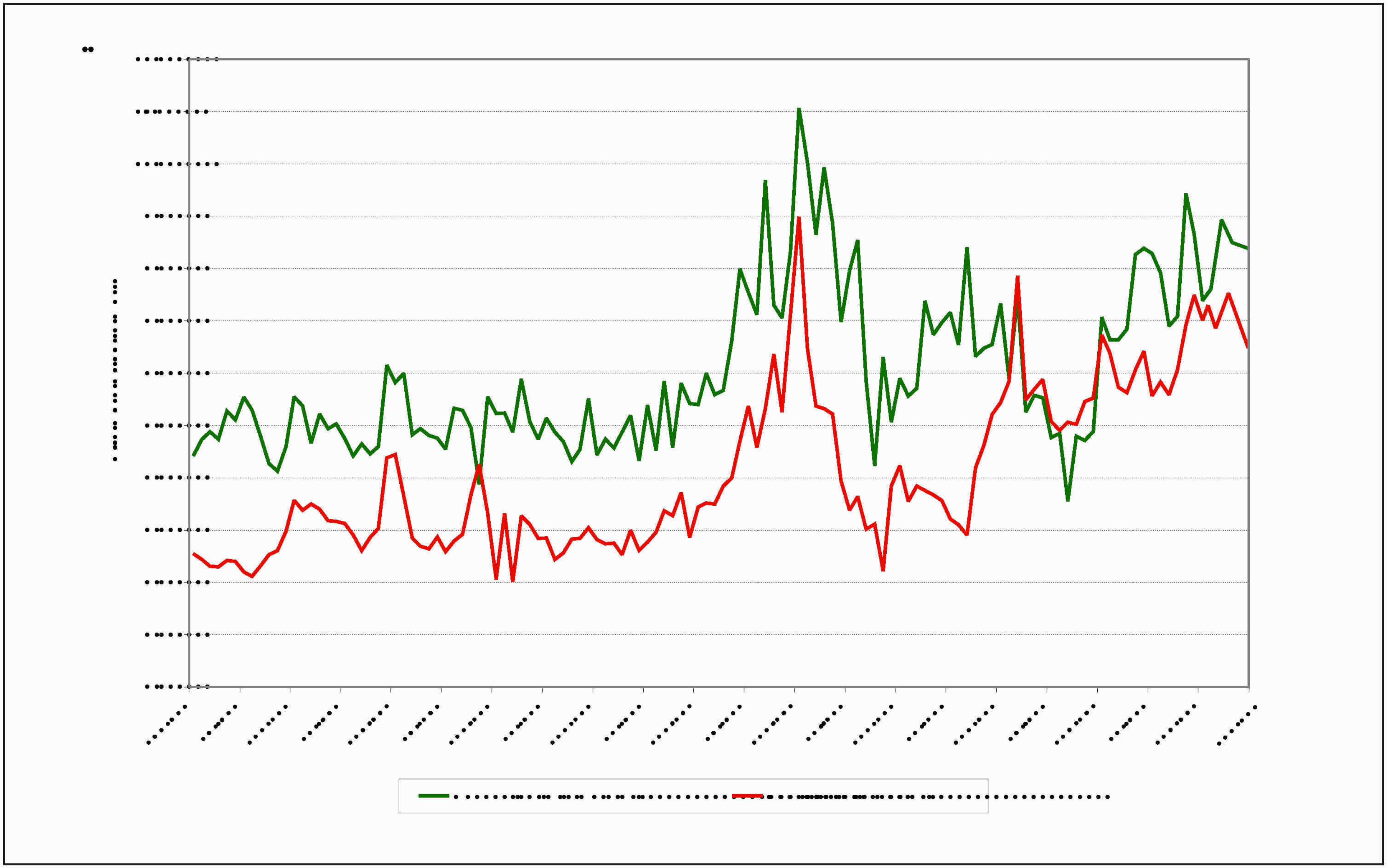
Second, a significant proportion of the new electric power generation in the Northeast U.S. is gas-fired. For example, in New York, fully 50% of the generating capacity for 2005 is either gas-fired or dual-fueled (capable of burning oil or natural gas) (NYISO 2005, page 17). During periods of extreme winter weather, this produces coincident demand spikes for both natural gas and power.

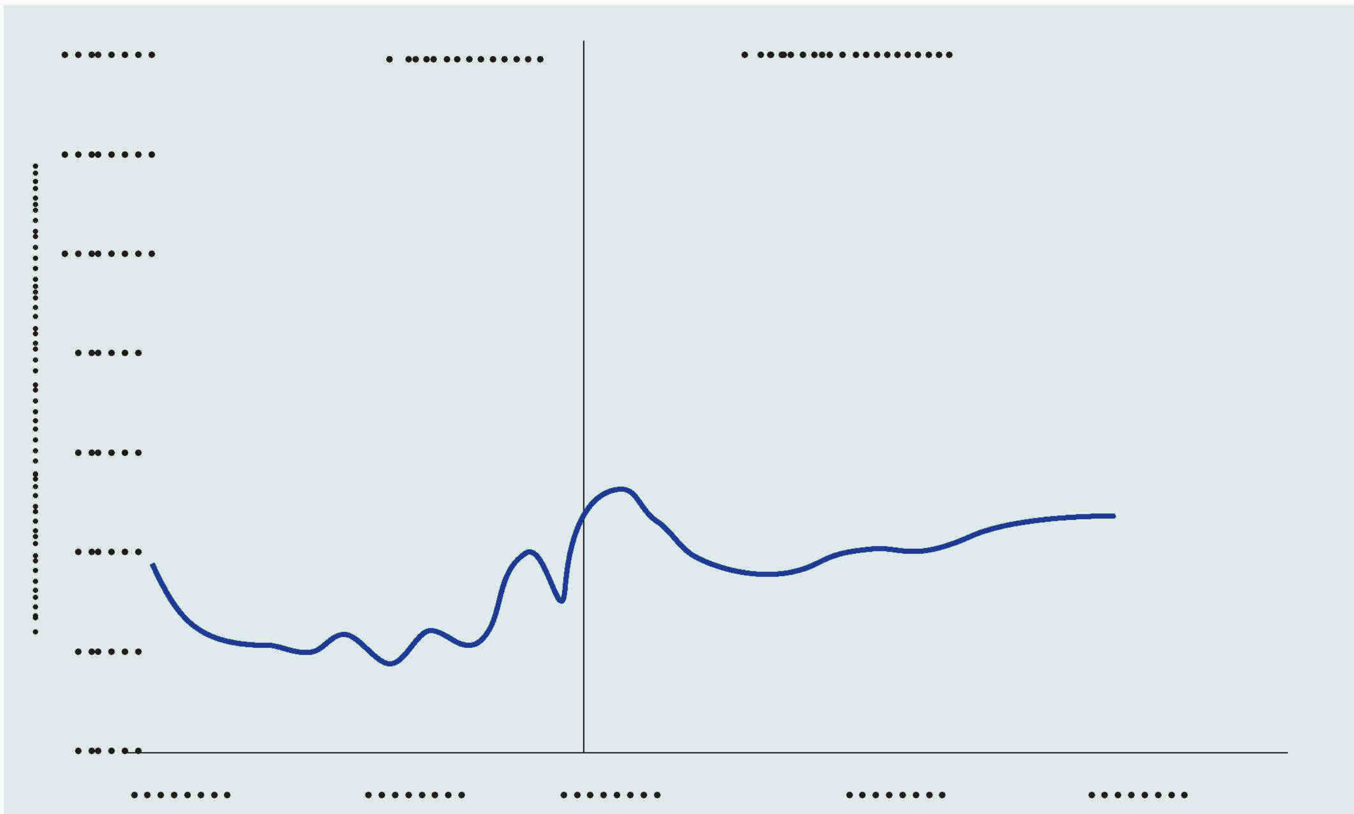
The need to address these issues of increasing price levels and volatility has been noted recently in the NYISO's recent publication *Power Trends 2005*: "The nation in general, and the Northeast in particular, must fashion an effective fuel diversity strategy for dealing with the increasing use and dwindling domestic reserves of natural gas" (NYISO 2005, page 19).

While the data above speaks to recent issues with natural gas pricing, there is a need for LNG to moderate long-run increases in natural gas prices. In its *AEO 2005*, the EIA forecasts that over the longer term, beginning in 2011, wellhead and delivered natural gas prices are projected to increase, largely in response to the higher exploration and development costs associated with smaller and deeper gas deposits in the remaining domestic resource base (*see* Figure 1-6). Gradually rising prices are anticipated over the remainder of the forecast period to 2025. Absent LNG imports, New York and Connecticut, currently positioned at the end of the continental gas transportation system, will be the most affected by this rising price trend.

1.2.2.4 Need for LNG

The projected growth in natural gas supplies to meet future need depends on unconventional domestic production, natural gas from Alaska, and imports of LNG (EIA 2005a, page 8). LNG imports have become an increasingly important part of the U.S. energy market due, in part, to higher natural gas prices, increased competition, and technological advances that have lowered the costs for liquefaction, shipping, storing, and regasification (EIA 2004, page 39). Global energy providers continue to increase natural gas exports by linking large, isolated gas reserves to existing global markets that are in need of a diversified and reliable natural gas supply. The lower supply costs of LNG, the increase in demand for natural gas, and the projected declines in domestic natural gas reserves all point to LNG imports playing an integral part in meeting the long-term energy needs of the U.S. in general, and New York and Connecticut in particular.





According to the EIA's *AEO 2005* (EIA 2005a), natural gas consumption in the U.S. is currently about 23 tcf per year and is expected to increase to about 31 tcf per year by 2025. Traditional natural gas supplies from the Gulf Coast and western Canada will meet only 75% of this increase in demand, necessitating the acquisition of additional supplies from Alaska and from other parts of the world in the form of LNG. In order to offset the imbalance between domestic supply and consumer demand, LNG imports to the U.S. are projected to increase from 0.4 tcf in 2003 to more than 6.4 tcf by 2025 (EIA 2005a, page 8).

The U.S. in general and the New York and Connecticut region in particular face a projected critical period over the next 10 to 15 years in meeting the energy needs of consumers. Volatility of natural gas prices experienced in New York and Connecticut over the past few years is symptomatic of the growing imbalance between energy demands and available supplies. While continued development of alternative energy sources, such as renewables, and investment in energy efficiency programs will help, the region needs a growing supply of natural gas to heat and cool homes, grow the economy, feed industries, and avoid power shortages until these new energy sources can provide sufficient supply to meet demands.

As the cleanest burning fossil fuel, natural gas is the fuel of choice in the U.S. for new power generation, residential heating, and commercial and industrial applications. This is due in part to the efficiency gains of new technologies, lower initial investment costs, relative ease in sitting new plants, and lower pollutant emissions. Most of the power load increase over the last several years was served by the introduction of new power plants fired by natural gas and No. 2 fuel oil. U.S. electric utilities consumed approximately 23% of the total natural gas used in the U.S. in 2003 (EIA 2005a, page 95).

Given the critical need for new energy supplies in the Region and ongoing air quality concerns, these energy supplies should be cleaner burning than the fossil fuels that currently supply much of the region's energy. According to the 2002 New York State Energy Plan (NYSERDA 2002), natural gas demand in the state is expected to grow nearly 38% by 2020 from 2002 levels. This growth is driven largely by electric generation, which itself is projected to grow approximately 23% by 2020. This trend is similar in Connecticut, where almost all new generation capacity (installed or under construction) since 1999 is fired with natural gas.

The Connecticut Energy Advisory Board (CEAB) advocates the enhancement of natural gas infrastructure in relationship to its growing dependence on LNG as a component of New England's natural gas supply (CEAB 2005, page 23). The Connecticut State Energy Plan forecasts that the consumption of natural gas for energy generation will nearly double from 24% in 2002 to 47% by 2008. New York State also supports the development of additional energy supplies and infrastructure to meet its growing energy needs (NYSERDA 2002, page S-4).

On-shore LNG import terminals are currently operating in Everett, Massachusetts; Lake Charles, Louisiana; Cove Point, Maryland; and Elba Island, Georgia. All of these locations have planned expansions of their facilities to meet the growing demand for LNG supplies (EIA 2004, page 91). Additional facilities are proposed in New England and proposed or permitted for construction elsewhere in the lower 48 states, providing LNG imports for the Gulf, Mid-Atlantic, South Atlantic, and Pacific coast states (EIA 2004, page 40) to help meet the need for natural gas in these market areas. However, none of the proposed expansions or new terminal proposals can meet the future demands of the New York and Connecticut markets.

A further discussion of the supply potential of existing and proposed LNG import terminals for the U.S. Northeast is provided in Resource Report 10 (Alternatives).

1.2.2.5 Project Deliveries

The Project will provide 1.0 bcfd of natural gas supply to the Region, with the ability to service a peak demand of 1.25 bcfd. Gas volumes will be delivered to an interconnection point with the IGTS system. From this point, gas can physically flow either south to Long Island and New York City, or north to Connecticut and upstate New York.

Broadwater conducted hydraulic simulations of the IGTS system, and demonstrated that the IGTS system is capable of taking away the Broadwater peak, nominal and lower send-out volumes from the interconnection point. This analysis indicates that flows of up to 600 to 700 million cubic feet per day (mmcfd) of natural gas could be physically delivered to Long Island and/or New York City from the Broadwater project. The balance of physical deliveries would be to the north of the interconnection point. Based on Broadwater's analysis, these rates could be achieved without pipeline looping or compression on the IGTS system.

1.3 LOCATION AND DESCRIPTION OF FACILITIES

1.3.1 General Project Description

The Broadwater terminal will be located approximately 9 miles from Long Island in Long Island Sound, in approximately 90 feet of water, and offshore of Riverhead, Suffolk County, New York (*see* Figure 1-1). The nearest Connecticut onshore point is approximately 10 miles from the proposed terminal location. The siting of the facility in its current location was determined based on a comprehensive and iterative process that evaluated potential terminal design concepts and sites throughout the entire Long Island Sound region, including both onshore and offshore locations. This siting evaluation assessed potential sites against a wide range of environmental and socioeconomic considerations as well as a number of technical engineering criteria (*see* Resource Report 10 for a full discussion of the siting considerations and alternatives evaluation process). With respect to socioeconomic considerations, a critical siting criterion was the distance of the terminal from shore, which determines security/safety, visual and noise impacts on populated areas. In addition, the length of the subsea connecting pipeline from the terminal to the IGTS pipeline was also a major consideration. Additional siting considerations included minimizing impacts on commercial and recreational fishing and boating, avoiding major subsea hazards, locating the terminal away from established or recognized shipping routes, determining suitable seafloor conditions for pipeline and mooring system installation, and many other important factors.

The primary components of the Project include the following new facilities:

- An LNG regasification facility consisting of an FSRU hull incorporating LNG receiving and storage, mooring system, process facilities, utility systems, ancillary facilities, and safety systems; and

- An approximately 21.7-mile-long subsea connecting pipeline.

The proposed FSRU will be a floating facility centrally located in Long Island Sound. A conceptual diagram of the proposed FSRU is provided on Figure 1-2. The FSRU will provide 1.0 bcfd of natural gas supply to the Region, with the ability to service a peak demand of 1.25 bcfd.

By locating the facility in the middle of Long Island Sound, Broadwater will be able to avoid the need for dredging that would be associated with shoreline terminals to accommodate LNG ships and minimize safety concerns of residents on both the Long Island and Connecticut shorelines. The steel hull of the FSRU will measure approximately 1,215 feet (370 m) in length, 200 feet (60 m) in width, and rise approximately 80 feet (25 m) above the water line to the trunk deck, as shown on Figure 1-2. The FSRU's draft is approximately 40 feet (12 m). The FSRU will be built in a shipyard suitably equipped and capable of constructing LNG carriers. After completion at the shipyard, the FSRU will be towed to the site. All LNG storage will be integrated into the hull of the facility, with some process equipment located on its deck. The FSRU will be designed to provide safe (temporary) storage and containment of LNG in its storage tanks.

The FSRU will be secured in place in Long Island Sound via a YMS attached to a tower structure that is secured to the seabed. The YMS and tower structure allow the vessel to orient in response to the prevailing wave, wind, and current conditions. The FSRU will be equipped with electrically powered azimuth stern thrusters to assist if required to maintain a constant heading during mooring operations with LNG carriers. The FSRU will have a single berth on its starboard side to accommodate a single LNG carrier for off-loading of LNG. Living quarters to accommodate approximately 30 permanent and 30 temporary (i.e., during commissioning, training, shutdowns and maintenance) crew members will be located on the facility aft of the LNG storage and containment area.

Broadwater will also construct an approximately 21.7-mile, 30-inch-outside diameter subsea connecting pipeline that will deliver regasified LNG to the existing IGTS pipeline that crosses western Long Island Sound between Milford, Connecticut, and Northport, Long Island (*see* Figure 1-1).

Detailed offshore marine surveys of the proposed pipeline corridor and FSRU location were conducted during 2005 to determine the final placement of the FSRU and pipeline corridor. The offshore surveys evaluated archeological, engineering, and hazard survey data and environmental conditions to select a preferred pipeline route.

Descriptions of the major individual components that make up the Project are provided below. More detailed design specifications for the FSRU are described in Resource Report 13 (Engineering and Design Material).

1.3.2 FSRU Facilities

1.3.2.1 Overview of FSRU

The preliminary design of the FSRU, as described below, will be finalized upon Project authorization, and will be built to conform to International Maritime Organization standards. A third party ship classification society such as the American Bureau of Shipping (ABS) will verify and certify the final design and construction. Primary FSRU components, which are discussed in greater detail below, include:

- A Yoke Mooring System;
- LNG Storage and Vaporization Facilities;
- LNG Receiving Facilities;
- Power Generation;
- A Ballasting System;
- Utilities;
- Storm Water Handling;
- Crew Accommodations and Command and Control Facilities; and
- Safety System.

The FSRU would be constructed at an overseas shipyard that has yet to be selected. The selection of a shipyard will be made on an international basis with an assessment of the shipyard's capacity, ability, and proven track record for LNG shipbuilding project construction. Options would be:

- Daewoo Shipbuilding & Marine Engineering, Korea
- Samsung Heavy Industries, Korea
- Hyundai Heavy Industries, Korea
- Mitsubishi Heavy Industries, Japan
- Mitsui Engineering & Shipbuilding, Japan
- Chantiers de l'Atlantique, France
- IZAR Construcciones Navales, Spain

A facility to construct the YMS has not been determined at this time. The selection of a suitable contractor and facility will be made on an international basis with an assessment of the contractor's capacity, ability, and proven track record for this type of project construction. The construction site is expected to be the same shipyard selected for the FSRU.

A U.S. shipyard may be considered for construction of the FSRU or the YMS only if no changes to structure and operation of the shipyard would be required to construct the FSRU and/or its mooring system.

The FSRU itself will be non-propelled but will be equipped with one pair of stern azimuth thrusters. The FSRU will be a vessel-shaped, double-hulled facility, built specifically to transfer, store and regasify LNG. Material for hull construction for the FSRU will be of mild steel (structural steel that contains low amounts of carbon—the most common form of steel) and higher tensile steel, which will be approved by the appropriate ship classification society.

In addition to the facilities discussed below, the FSRU will include additional on-deck structures. The FSRU will be equipped with three deck cranes for equipment and supply distribution. A helideck for emergency transport will be located on top of the accommodations, as well as a single combined signal and radar mast. A flare stack, extending approximately 197 ft (60 m) above the trunk deck, will be located toward the fore of the FSRU and will be used for only emergency venting or flaring of natural gas. The flare stack will not be used under normal operational conditions and will utilize an automatic pilot light.

The FSRU hull is of double hull design similar to that of an LNG carrier. The double hull is applicable to the flat bottom, sides and upper/trunk decks of the FSRU such that the entire cargo containment system is protected by a double hull.

To protect the hull of the FSRU from any LNG spill that may occur, drainage is managed by providing the coaming and draining systems that diverts LNG to a disposal point on the port side of the FSRU. The disposal point is determined such that there would be no interference with any other vessel that may be in the immediate vicinity of the FSRU. LNG spills from loading arms are also mitigated using stainless steel cladding on parts of the FSRU hull at loading points, combined with a water-curtain spray. Resource Report 13 contains LNG spill details.

1.3.2.2 Design Codes and Standards

The FSRU will be designed and constructed to meet an extensive array of design codes and standards as well as the legislative standards of national and international authorities. While no single standard directly addresses the concept of the proposed FSRU, the FSRU is based on existing related facilities, and individual elements are addressed in various codes. Moreover, the services of a Ship Classification Society will be retained to ensure compliance with national and international codes and standards. As presented in Appendix B, the ABS has reviewed the preliminary FSRU design, and determined that the FSRU meets ABS Ship Classification Rules, and can be built and receive formal Class designation from ABS. Further details of the relevant design codes and standards are provided in Resource Report 13 (Additional Information Related to LNG Facilities).

1.3.2.3 Major Equipment on Deck

The FSRU has various regasification process and utility equipment mounted on deck, as depicted on Figure 1-7 and described below.

Gas Turbine Generators

Three units mounted on the aft trunk deck will generate all electrical power for the FSRU. Each turbine with its casing and air intake has a footprint area of approximately 50 x 8 ft (15 x 2.5 m). The maximum height above the deck at the air intake is approximately 33 ft (10 m).

Selective Catalytic Reduction (SCR)

The exhaust of each gas turbine is fitted with SCR technology for air pollution control. Each SCR has a footprint of approximately 21 x 21 ft (6.5 x 6.5 m) and rises approximately 33 ft (10 m) above the trunk deck. From the SCR, the exhaust gas passes to a Waste Heat Recovery Unit (WHRU) whereby heat is recovered to the regasification heating system. Each WHRU has a footprint of approximately 72 x 16 ft (22 x 5 m) and rises approximately 65 ft (20 m) above the trunk deck.

Nitrogen Plant

This plant, which consists of air compressors and membrane nitrogen generating units, is described below. The plant is arranged on the starboard aft trunk deck and has a footprint of approximately 125 x 105 ft (38 x 32 m) and rises approximately 24 ft (7.5 m) from the trunk deck.

LNG Loading Arms

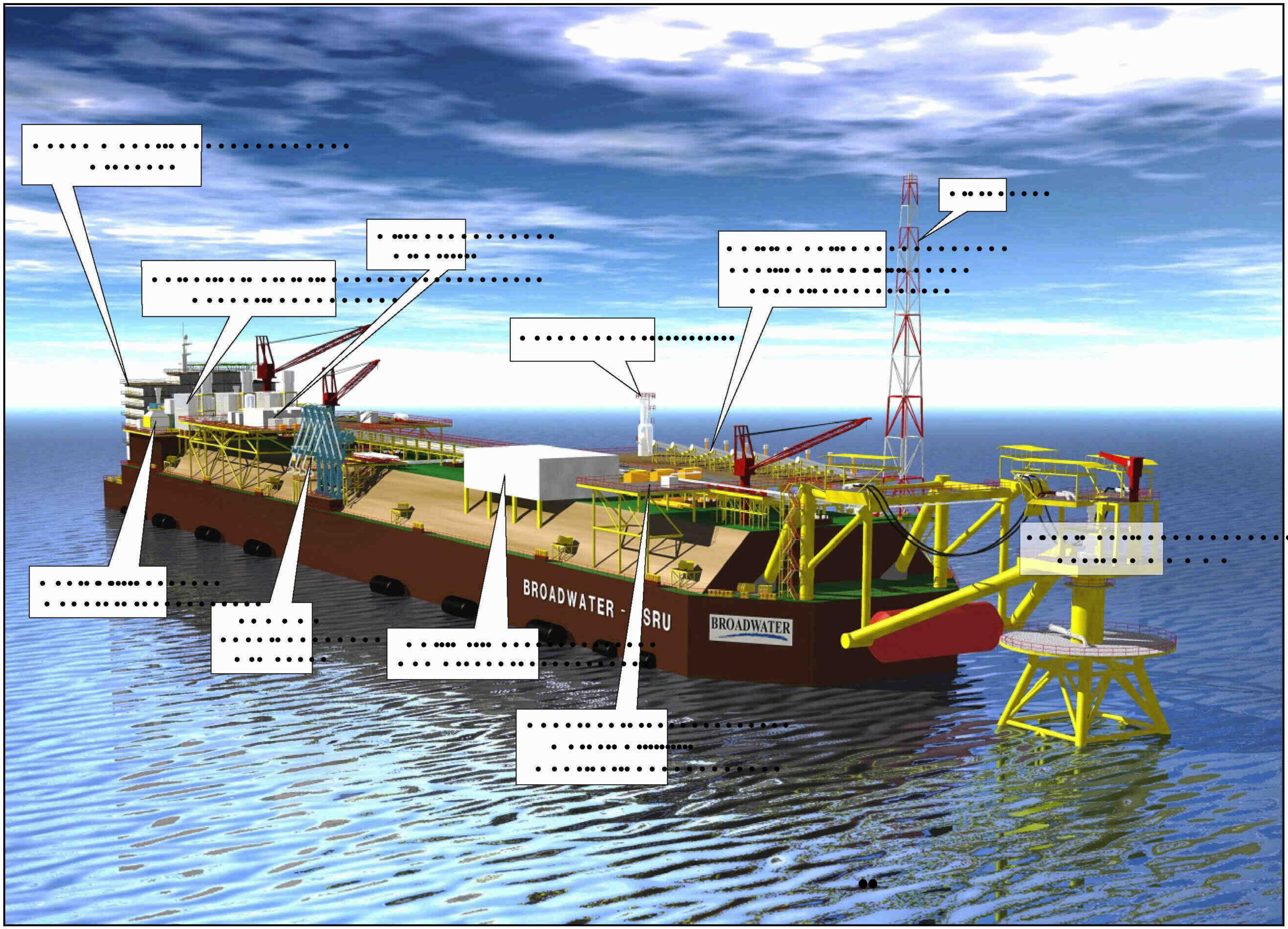
The fixed loading arms connect to the LNG carrier for receiving LNG to the FSRU. There are four arms mounted on the starboard side mishap of the FSRU. When stowed, they have a footprint of approximately 62 x 16 ft (19 x 5 m) and rise approximately 85 ft (26 m) above the upper deck or 55 ft (17 m) above the trunk deck level.

Recondenser

This regasification process component recondenses boil off gas (BOG) from the cargo tanks and nitrogen from the previously described nitrogen injection plant. It is located on the forward port side of the FSRU and is supported on a raised platform. It is approximately 15 ft (4.5 m) in diameter and rises 42 ft (13 m) above the trunk deck level.

Boil Off Gas Compressors

Three BOG compressors for NG vapor return to the LNG carrier and recondenser and for fuel gas supply to the process heaters are arranged in a separate house on the starboard trunk deck. The compressor house has a footprint of approximately 105 x 62 ft (32 x 19 m) and rises approximately 31 ft (9.5 m) above the trunk deck.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Shell and Tube Vaporizers

STVs are mounted on a raised platform on the port side of the trunk deck and forward of the recondenser. The vaporizers use a glycol/water mix heating medium to regasify the process LNG. LNG is supplied to eight STVs by eight individual vertically mounted and adjacent HP LNG pumps. Each STV is of approximately 6.5 ft (2 m) diameter and is approximately 55 ft (17 m) in length. The STVs extend approximately 15 ft (4.5 m) above the platform or 38 ft (11.5 m) above the trunk deck level. Each of the eight HP LNG pumps is of approximately 8 ft (2.5 m) diameter and rises 25 ft (7.6 m) above the trunk deck level.

Superheaters

Three superheater units are mounted on a raised platform 20 ft (6 m) above the trunk deck level) on the forward starboard side of the trunk deck. They are used to heat the vaporized gas to send-out temperature. Together, they have a combined footprint of approximately 52 x 10 ft (16 x 3 m) and extend only 7 ft (2 m) above the raised platform.

Metering and Odorization

This equipment is mounted on the raised platform adjacent to the superheaters and houses gas measurement flow meters and odorization for transfer to the subsea connecting pipeline. In total, the metering house has a footprint of approximately 50 x 75 ft (15 x 23 m) and extends approximately 7 ft (2 m) above the raised platform.

Cranes

Three utility cranes are fitted for general lifting service. One is located forward, having a radius of 95 ft (29 m) and a stowed height above the trunk deck of approximately 52 ft (16 m); two are located aft, each having a radius of approximately 124 ft (38 m) and 138 ft (42 m) and a height above the main deck of approximately 52 ft (16 m) and 85 ft (26 m), respectively.

Flare

The FSRU will be equipped with a flare for emergencies only. The flare provides for safe handling of vapors in the event there is overpressure in the storage system. The flare will rise approximately 197 ft (60 m) above the trunk deck.

1.3.2.4 Yoke Mooring System

The FSRU will be moored in place using a robust YMS that allows the FSRU to weathervane around the mooring jacket. The YMS is attached to the stationary tower structure, secured to the seafloor by four legs and is designed to withstand extreme storm events. The primary YMS design will safely accommodate the most severe weather data that can credibly occur in the area, including hurricanes. *See* Resource Report 11, Safety and Reliability, Section 11.3.4.1 for a more detailed description. The total area under the open design structure is about 13,180 ft^2 (1,225 m^2).

See Figures 1-8a and 1-8b for depictions of the YMS. The tower consists of the following components:

Jacket

The jacket is a four legged tubular steel structure attaching the tower to the seabed, each leg being of approximately 6.9 ft (2.1 m) diameter. Four corner piles will be installed to approximately 230 ft (70 m) into the seafloor. The corner piles will be installed in a square of approximately 115 ft (35 m) to a side. The jacket will be attached to the piles and welded and grouted in place. Located within the jacket is the pipeline riser that connects to the remainder of the pipeline on the sea floor. The pipeline riser will be secured to the insides jacket legs by bolted clamps to provide protection against any waterborne impacts.

Mooring Head

The mooring head is located atop the jacket and supports the pipe work and equipment. The total height of the structure above the sea bed is approximately 223 ft (68 m) of which approximately 134 ft (41 m) will be above sea level. The mooring head at the upper most part is approximately 55 ft (17 m) in width. The YMS is connected to the mooring support structure (MSS) on the FSRU via a yoke of approximately 131 ft (40 m) in width, and the YMS kingpost centerline will stand approximately 164 ft (50 m) forward of the FSRU bow.

Yoke

The yoke is a tubular, triangular frame that is connected to the mooring head via a roll-and-pitch articulation and incorporates a counter weight. The mooring yoke is a tubular steel triangular frame with the apex connected to the turntable. The structure has roll and pitch articulation at its apex, and a tubular ballast compartment connecting the opposite ends of the two side members. The ballast tank remains empty until it is lifted and connected to the two mooring arms so it weighs less during lifting/connecting operations, and so it floats prior to the FSRU arrival.

Once hooked up to the FSRU, the yoke ballast compartments will be filled with 1,984 short tons (1,800 tonnes) of fresh or distilled water, which will have been treated with a benign proprietary corrosion inhibitor so as to prevent any internal corrosion of the ballast space. This ballast water acts as counterweight to help restore the FSRU to equilibrium should it move under environmental effects. Although not anticipated, if any inhibited water must be drained, it shall be collected and disposed of at a suitable onshore facility.

Access to and from the FSRU to the mooring tower is via the yoke through a retractable gangway, ladders attached to the mooring arms, and a series of platforms and ladders installed on the yoke structure.


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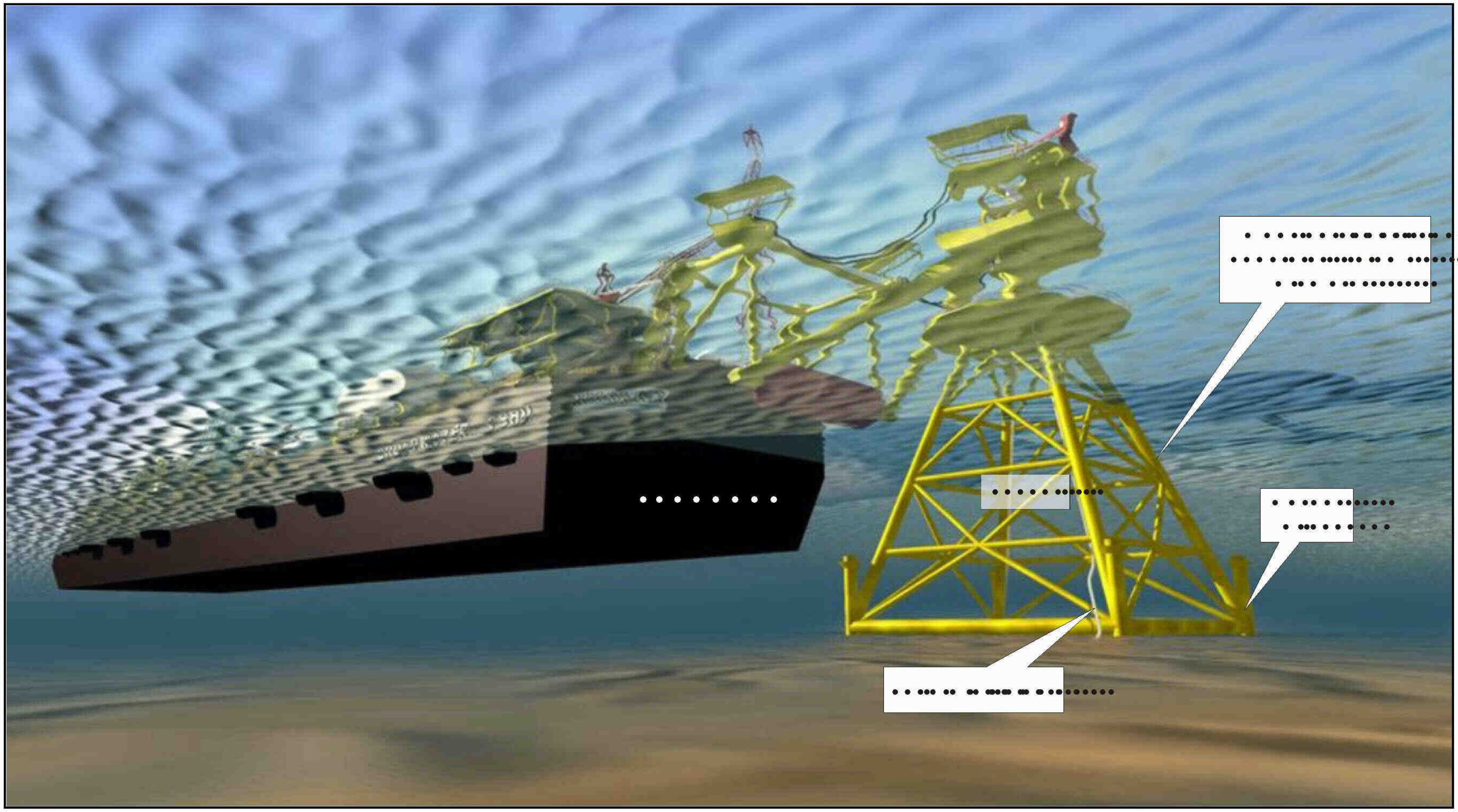

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Mooring Support Structure (MSS) on FSRU

The MSS on the FSRU consists of a tubular frame mounted onto the bow of the FSRU. The structure overhangs the bow of the vessel to provide clearance for the yoke. The MSS mounted on the FSRU's bow consists of a tubular steel space frame structure, which is welded into reinforced areas in the vessel's bow. The structure overhangs the bow of the FSRU to ensure clearance between the mooring yoke and the FSRU during the worst design condition displacements. The two mooring legs that support the ballasted end of the mooring yoke are suspended from the upper outermost edge of the structure via uni-joints.

The MSS is designed not only to support the two mooring legs, but also to act as a tie-in point for the send-out gas flexibles, utility transfer hoses, and umbilicals spanning from the mooring tower. Access to the yoke via a stairway up from the FSRU deck and ladders attached to the mooring legs is also provided by the MSS. Reinforced lift attachment points and lugs are provided on the MSS to facilitate the lift and connection of the yoke to the mooring legs during installation of the FSRU when it arrives on site.

Jumpers

The transfer of the send-out gas between the FSRU and the yoke is achieved through two 16-in (405-mm) inside diameter, 54.5-ft (16.6-m) -long jumpers that are suspended between the MSS on the FSRU and the turntable structure on the fixed mooring tower. The jumpers have a wall thickness of 2.2 in (56 mm) and are composed of stripwound stainless steel, rubberized textile plies with steel cable reinforcement, and an elastomer external coating. The means of connection between transfer lines and the pipeline riser is described in detail in Resource Report 13 (Engineering and Design Material).

1.3.2.5 LNG Storage and Vaporization Facilities

1.3.2.5.1 LNG Containment

The FSRU will temporarily store LNG in membrane storage tanks incorporated into the hull of the structure with a total net storage capacity of 350,000 m^3 (approximately 8 bcf of natural gas). The storage capacity of the FSRU will be divided between 8 LNG tanks, each having an approximate volume of 44,850 m^3. The stored LNG will be maintained at a temperature of minus 260 ºF and a normal operating pressure of 1 to 3 pounds per square inch (psi), closely approximating atmospheric pressure. Each LNG storage tank will be equipped with a retractable pump that will be used to transfer LNG from storage to the vaporizer system. No mechanical means of refrigeration will be required because LNG is refrigerated (liquefied) at the sending site and transported in thermally insulated LNG carrier cargo tanks.

Using the Gaz Transport and Techigaz Mark III membrane tank system as an example, the main components of the containment system will include:

- A 1.2-mm-thick stainless steel primary barrier, consisting of an orthogonal system of corrugations to compensate for thermal contraction and mechanical ship deflections;

- Insulation, consisting of rigid polyurethane foam with reinforcing glass fibers between two plywood sheets, the thickness of which is determined to limit the boil off rate to 0.15% per day with cargo tanks at 98% full; and

- A secondary barrier, comprised of laminated composite material made of two glass cloths with aluminum foil (called Triplex) in between, for tightness. The secondary barrier, provided to contain LNG in case of leakage through the primary barrier, is inserted in the insulating structure.

The membrane and insulation system transmits cargo pressure to the inner steel hull structure of the FSRU.

The Gaz Transport and Techigaz No. 96 membrane tank system may be used as an alternative to the Gaz Transport and Techigaz Mark III.

All materials, material testing, and approval of manufacturers for the LNG containment system will be accordance with the requirement the Classification Society standards. All materials will be suitable for the specified temperatures. The material used for construction of the membrane primary barrier will be chromium nickel stainless steel with very low carbon content.

1.3.2.5.2 Vapor Handling System

During normal operations, a small amount of the LNG within the storage tanks will vaporize, primarily due to heat inputs from the ambient conditions, in-tank pumps, and changes in barometric pressure. Vapor will also be generated during LNG carrier unloading due to the displacement of tank vapors as the tanks are filled with LNG.

A vapor-handling system will collect and transfer BOG originating from the storage tanks either back to the LNG carrier or to a recondenser, which is used to re-liquefy all of the BOG.

During LNG carrier unloading operations, a proportion of the BOG will be returned to the ship via dedicated BOG compressors to compensate for the volume of liquid pumped out to maintain the carrier's tank pressure.

Any generated BOG that is not returned to the carrier, or BOG that is normally generated when no FSRU loading operations are taking place, will be sent by the compressors to the recondenser, where it will be condensed back into liquid by direct contact with LNG. The recondensed BOG is then combined with the send-out LNG prior to being pumped up to pipeline pressure in the send-out pumps and passing through the vaporizers. The FSRU will have three BOG compressors, two operational and one installed as a spare.

The BOG compressors act as a pump for BOG for its delivery to either the LNG carrier or the recondenser. The recondenser is a vertical chamber that allows vapor and system LNG to come into direct contact, such that the gas is condensed by the LNG back into the liquid stream.

1.3.2.5.3 LNG Vaporization System

The LNG from the LNG cargo tanks on the FSRU will be pumped from the tanks through individual in-tank pumps.

The LNG from the cargo tanks passes through a recondenser where BOG is introduced and re-liquefied. On exiting the recondenser, the LNG passes to a manifold where it is divided into a number of regasification trains each comprised of a high-pressure pump and vaporizer. The pumps raise the LNG pressure to that suitable for entry to the vaporizers. The regasification plant is designed to vaporize LNG at a peak capacity of 2,500 m^3/hour.

The FSRU will have eight STVs that will vaporize LNG to natural gas. From there, the vaporized gas is further heated to up to 144 ºF (62•C) in the printed circuit heat exchanger (PCHE) type superheaters, with send-out gas temperature being dependent on gas delivery requirements. The gas will then pass through a metering station prior to being routed to the transfer hoses of the mooring system and finally to the subsea connecting pipeline via the riser. Odorant will be added on the FSRU prior to injection into the subsea connecting pipeline.

Both the vaporizers and the superheaters use a closed loop, 50/50 glycol/water mix as a heating medium (supplied at a temperature between 162 ºF [72 ^{o}C] and 185 ºF [85 ^{o}C]). The primary heat source for the glycol/water system will be supplied by gas-fired process heaters and augmented by exhaust heat from the WHRUs of the gas turbines. There is no use of, or discharge to, seawater from the proposed vaporizer system. The fuel source for the process heaters will be vaporized LNG tapped from the vaporizer system. The process heaters will consume approximately 6 mmcfd of natural gas at 100% load level.

The process heaters will be equipped with Selective Catalytic Reduction (SCR) units to reduce the nitrogen oxides (NO_X) content of the exhaust gases down to 2.5 parts per million (ppm) to meet the region's strict NO_X control requirements. An SCR unit operates by continuously injecting a small amount of aqueous ammonia into the process heater exhaust stream and then passing the exhaust gases through a catalyst. The ammonia is needed to make the chemical reaction in the catalyst be as effective as possible in reducing NO_X. Volatile organic compounds (VOCs) and carbon monoxide (CO) content will also be reduced to 10 ppm or less by use of special catalysts. These special catalysts do not require anything to be added to the exhaust to reduce VOC and CO emissions.

The delivery, storage and handling of aqueous ammonia will be addressed at the detailed design stage. Equipment and procedures will conform to Class and manufacturers' requirements, including Material Safety Data Sheets.

1.3.2.5.4 Diesel Oil

Other than LNG as a fuel source, diesel oil is the only liquid fuel to be stored onboard. This will be used for:

- Gas turbine (commissioning and back only);
- Diesel alternators (including emergency unit);
- Diesel engine driven fire pumps; and
- Lifeboat engines.

All fuel (and lubricating oil) tanks will be of welded steel construction integrated into the hull and well secured. The main tanks are as follows:

- Diesel oil storage tank: two x 2,000 m^3;
- Diesel oil service tank: two x 50 m^3; and
- Emergency generator diesel oil tank: one x 1 m^3.

Other small oil tanks sizing and storage locations will be defined at the detailed design stage, including storage of small packaged drums.

All fuel and lubricating oil tanks and systems will be fitted with safety and spill containment features according to Class requirements and this will be further defined at the detailed design stage. Safety and spill features will include:

- Drip pans or coamings, where appropriate;
- Quick closing, remotely operated tank isolating valves; and
- Heat-resistant level gauges/alarms.

Oil handling procedures will be developed within the FSRU Safety Management Systems and conform to United States Coast Guard (USCG) Oil Transfer Procedures.

1.3.2.5.5 Nitrogen Injection

In order to meet gas quality limits of the existing IGTS tariff, nitrogen will be injected into the regasified LNG, up to a maximum of 4% by volume, as may be required. Nitrogen injection facilities will be located on the FSRU and will utilize membrane technology to produce the required nitrogen from the ambient air.

1.3.2.6 Berthing and Unloading Facilities/LNG Receiving Facilities

The berthing and unloading facilities at the FSRU, comprised of liquid/vapor loading arms, will include a single LNG carrier berth located midship on the starboard side of the FSRU. The berth can accommodate one LNG carrier with a capacity in the range of 125,000 up to a potential future capacity of 250,000 m^3 at a time.

The offloading area of the FSRU will support all equipment needed to safely off-load LNG from the LNG carrier and will consist of:

- Four LNG loading arms;

- Loading arm power packs and controls;
- All necessary piping and manifolds;
- Gas and fire detection, fire protection, and firefighting facilities;
- Life-saving equipment;
- Provisions for telecommunications;
- Ship/shore access gangway;
- Small crane; and
- Cold splash protection.

LNG transfer from the LNG carrier to the FSRU is achieved via dedicated unloading arms as are standard for onshore terminals. The four unloading arms comprise two liquid lines, one vapor return line, and one spare liquid/vapor line. Each arm has a capacity of 5,000 m^3/hr liquid or 15,000 m^3/hr vapor using 16-inch standard arms with quick disconnect coupling, a powered emergency release coupler, and a manifold guidance system. Loading arm safety is integrated into the ESD system as described below in Section 1.3.1.12.

The FSRU and LNG carrier manifold and loading arms will be of suitable material for LNG handling (e.g., stainless steel SS316L or similar) and will be further defined at the detailed design stage.

1.3.2.7 Power Generation

1.3.2.7.1 Gas Turbines

Broadwater proposes to install three 22-megawatt (MW) aero-derivative, coupled generator sets, with one unit serving as a spare. The primary fuel for the gas turbines will be natural gas (supplied from and reduced in pressure from final process send-out). One of the turbines will be designed to use a secondary fuel (low-sulfur diesel oil with full liquid fuel conditioning) and filtration system incorporated for use in emergency situations.

A horizontal WHRU will be attached to the exhaust end of each of the gas turbines to provide heat to the LNG superheaters and to the ancillary heating water system. Turbine exhaust gas will pass through a CO catalyst to reduce CO to 10 ppm or less and then through a heat medium (glycol-water) tube bundle.

As with the process heaters, the gas turbines will be equipped with SCR units to reduce the NO_X content of the exhaust gases down to 2.5 ppm or less in order to meet the region's strict NO_X control requirements. The SCR units will be located after the primary heat exchange bundle. A second heat exchange bundle is located downstream of the NO_X reduction catalyst bed to recover most of the remaining heat in the exhaust stream.

1.3.2.7.2 Diesel Engines

There will be three diesel generators, all above the upper deck. One of these generators will be a self-contained and suitably sized emergency diesel generator for black start/first start operations.

1.3.2.8 Seawater Withdrawal and Discharge Systems

The FSRU will have four seawater intakes comprised of two main intakes located on the port and starboard sides of the bottom of the FSRU hull, and two fire pump intakes located on the fore and aft of the bottom of the FSRU hull.

Sea chest intakes will withdraw water from an approximate depth of 40 feet (12 m). The sea chest intakes will have a coarse grate (grate size approximately 4 inches x 2 inches) at the interface between the seawater and the FSRU hull. Intake velocities will be limited to 0.5 feet/second (0.15 m/s), which will allow motile organisms to easily swim away from the intakes.

The port and starboard sea chests will be connected by an approximately 35-inch crossover pipe. Only one intake will operate at any given time.

The main seawater intakes will supply water for:

- Ballast: ballast intake and discharge will be based on the volume of LNG being received by the FSRU and/or being revaporized and sent out by the FSRU (*see* Section 1.3.2.8.1 below);

- Desalination plant (reverse osmosis unit): two pumps will be available, with only one pump in operation at any time;

- Marine growth prevention system;

- Bilge and general service pumps: to provide a water curtain for the LNG loading area;

- Inert gas scrubber cooling pump: for infrequent use only if cargo tank inerting and aerating is required; and

- Sea water cooling pump: for emergency use only if the glycol-water system fails.

In the sea chest, sodium hypochlorite is added at a continuous low dose of 0.2 ppm, resulting in a residual chlorine concentration of 0.01 to 0.05 in the seawater used by the FSRU. Sodium hypochlorite is produced from the intake sea water via an electro-chlorination unit which, by passing an electric current through the side steam seawater via two concentric titanium electrode tubes, converts the sodium chloride in the seawater to safe, low concentration sodium hypochlorite, which is re-injected into the sea chest. Water is treated in this way to prevent marine growth on the FSRU seawater systems.

After treatment with sodium hypochlorite, water will pass through an in-line 5-mm screen to a manifold where the water is directed for various use throughout the FSRU.

The quantities of water withdrawals and discharges associated with the FSRU are provided in Resource Report 2 (Water Use and Quality).

Water ingested by either of the two fire water intakes will not be treated with sodium hypochlorite.

1.3.2.8.1 Ballast System

The FSRU will be equipped to maintain its draft, trim, and stability within a specific range by using a water ballast system. The port and starboard sea chests will provide the seawater for the ballast system.

Normal ballast water intake will occur in conjunction with the continual send-out of natural gas through the marine pipeline. Given that the density of LNG relative to sea water is approximately 0.45, to offset a daily vaporization and send-out of 2,000 m^3/hour, the FSRU will need to take on approximately 900 m^3/hr of seawater, or approximately 5.7 million gallons of water per day.

During LNG offloading from the carrier to the FSRU, the FSRU will need to discharge additional volumes of ballast water to offset the LNG transferred to the FSRU. During the course of the loading activities, discharge of ballast water will be as high as 4,500 m^3/hr to balance a loading rate of 10,000 m^3/hr. Total ballast water released from the FSRU will equal approximately slightly less than one half of the cargo volume offloaded. Therefore, for a 145,000 m^3 LNG shipment, the FSRU would discharge approximately 65,250 m^3 (approximately 17.2 million gallons) of ballast water.

The FSRU will be ballasted at the construction yard before commencing the tow to Long Island Sound. In compliance with the International Convention for the Control and Management of Ships Ballast Water and Sediments, a ballast water exchange will be completed during the voyage. Regulations require this to be conducted at least 200 nautical miles from the nearest land and in water at least 200 meters in depth, with an efficiency of 95% volumetric exchange of ballast water.

The International Convention is set forth in 33 CFR Subpart D - Ballast Water Management for Control of Nonindigenous Species in Waters of the United States.

1.3.2.8.2 Waste and Water Treatment

Operations on the FSRU will generate various types of waste material. Hazardous materials that will be onboard the FSRU include paints, solvents, ammonia, and odorant. In addition, lubricating oil will be stored onboard for use with various rotating equipment. Diesel fuel will also be onboard for the emergency diesel generator. Additional discussions of the primary waste types are presented below.

Paints and Solvents

FSRU maintenance activities will require the use of various paints, solvents, and other materials. These materials will be brought onboard in retail-sized containers and stored in compartments specifically designed and constructed for storage of hazardous materials and paints. Empty containers will be brought to shore for appropriate disposal or recycling.

Gray and Black Water

The FSRU will be equipped with an onboard treatment plant to treat all sewage and gray water generated onboard. If treatment plant options cannot meet the State of New York discharge requirements, all black water will be routed to a holding tank in the FSRU and shipped to shore for disposal at an approved facility. Any gray water generated by systems on the FSRU such as sinks, shower drains, and floor drains that may contain increased levels of detergents and nutrients would also be routed to a holding tank and shipped to shore for disposal at an approved facility.

For the onboard treatment plant, Broadwater will use a marine bioreactor (MBR) rather than a typical USCG treatment system. The discharge from the MBR, which will be located approximately 3 feet (1 m) below the water line, is anticipated to be approximately 2,000 to 5,000 gallons per day (8 to 19 m^3/d). The MBR provides an advanced treatment process that produces a discharge of much higher quality than a USCG treatment device, and provides Broadwater with the ability to be consistent with the Long Island Sound Comprehensive Conservation and Management Plan.

A typical USCG treatment device can achieve the following effluent quality standards:

- Suspended solids: 150 mg/L; and
- Fecal coliform: 200 counts/100mL.

Biological oxygen demand, pH, and chlorine are not parameters typically analyzed for treatment in this type of system.

The MBR system produces a much higher effluent quality and addresses more water quality parameters than a USCG treatment device. The MBR effluent quality standards include:

- Suspended solids: 3.1 mg/L;
- Biological oxygen demand: 2.6 mg/L;
- Fecal coliform: 10.6 counts/100mL;
- pH within acceptable limits for the original water source; and
- Chlorine: 0 μg/L.

Ammonia

Selective catalytic reduction (SCR) will be used to reduce air emissions of NO_X to levels in accordance with New York State requirements for Suffolk County. Aqueous ammonia will be used as part of the SCR process. Ammonia storage and handling procedures will be developed when the detailed FSRU design commences.

Odorant

Odorant is added to natural gas to give it a perceptible odor, even at low concentrations. Storage and handling procedures as well as the amount and type of odorant injected into the gas stream will be in accordance with regulatory requirements.

Only commercially available odorant will be used, and handling will be in accordance with the manufacturer's recommendations and the appropriate Material Safety Data Sheet. For logistical purposes, it is anticipated that International Standards Organization (ISO) tank containers will be used to transport and store the odorant onboard the FSRU. These containers typically have a capacity of 6,600 gallons (25,000 liters), and deck space will be provided on the FSRU for two containers with an appropriate spill containment arrangement around this area. For safety purposes, as the container is being emptied, the vapor space will be inerted from the FSRU nitrogen supply. Odorant spill procedures will be included within the terminal Spill Response Planning and Preparedness Plan for both transport and storage phases.

1.3.2.9 Drainage Systems and Deck Runoff

Broadwater will manage storm water runoff from atmospheric precipitation depending on the location on the FSRU. Uncontaminated storm water runoff from the FSRU will be comprised of rainwater and will be directed overboard via scupper drains. The volume of this runoff is dependent on the local level of precipitation and will be at ambient temperature when drained to the Sound. Runoff from any deck location that has the potential for oil and/or grease contamination will not be directed overboard. Runoff from these areas will instead be collected and routed to the bilge holding tank for shipment to shore for disposal at an approved facility. These practices ensure that storm water runoff does not contain hydrocarbon contaminants from the FSRU. Discharge during testing of the fire water bypass system will be overboard via scupper drains.

1.3.2.10 Other Facilities

1.3.2.10.1 Crew Quarters

The FSRU will have facilities to accommodate a permanent crew of up to 30 and a temporary crew of 30. For safety reasons, all living, dining, and recreational areas will be contained within the crew quarters to separate the processing area from the Accommodation Area.

1.3.2.10.2 Command and Control Facilities

Command and control facilities, including monitoring and control facilities for natural gas process activities, ballasting, communication, radar equipment, electrical generation, emergency systems, and thruster controls, will be located in a central control room in the Accommodation Area.

1.3.2.11 Safety Systems

1.3.2.11.1 Emergency Shutdown Systems

The FSRU will have emergency shutdown (ESD) systems to allow for the safe termination of operations in the event of an operational problem. The systems will allow for either the shutdown of individual sections of the FSRU or the entire facility, depending on the particular event.

The LNG carrier and the FSRU will each be equipped with their own ESD systems, which will be inter-connected in such a way that any unusual action on the FSRU or the carrier will automatically stop the unloading procedure onboard the ship. Details of the specific ESD systems with which the FSRU will be equipped are described in Resource Report 13 (Engineering and Design Material).

1.3.2.11.2 LNG Spill Drainage and Containment

To protect the hull of the FSRU from any LNG spill that may occur, coaming and draining systems will be provided to divert spilled LNG to a disposal point on the port side of the FSRU. The disposal point will be selected such that there would be no interference with any other vessel that may be in the immediate vicinity of the FSRU. LNG spills from loading arms are also mitigated using stainless steel cladding on parts of the FSRU hull at loading points, combined with a water-curtain spray. The LNG will leave no residue and will not have an impact on water quality. Resource Report 13 (Section 13.4) contains LNG spill details.

1.3.2.11.3 Fire Prevention

Fire prevention will be incorporated into the design and operation of the FSRU. All equipment and operations and maintenance procedures will be designed and developed to minimize the consequences of accidentally releasing flammable liquids or gases. The FSRU will be fully equipped with smoke and fire detection systems and a fire-fighting water system.

A separate fire-fighting (deluge) spray water system to cover the process area, crew accommodations, and lifeboats will be provided in accordance with USCG requirements. Additional details regarding fire protection systems and the Fire and Explosion Analysis are provided in Resource Report 13 (Engineering and Design Material).

1.3.2.12 LNG Carriers

LNG carriers will call at the Broadwater FSRU at a frequency of up to three times per week, depending on carrier size. LNG carriers usually retain a small amount of ballast during the loaded voyage for trim purposes. It is very unlikely that vessels will discharge any of this ballast within Long Island Sound, but in any event the water would be subject to a Ballast Management Plan, as required by international regulations.

During offloading, the LNG carrier takes on ballast water through a dedicated ballast system to maintain trim, stability, and limit hull stresses. The water intake locations differ from vessel to vessel, but typically are within the machinery space and either on the bottom of the hull or towards the bottom of the side-shell in the vicinity of the turn of the bilge. Intake systems are of similar design to the FSRU. With an LNG discharge rate of 10,000 m^3/hr, the LNG carrier will need to take on ballast water to maintain trim, although an LNG carrier will typically leave the FSRU at a reduced draft (i.e., with higher freeboard) than when it arrived. The total amount of ballast taken on will vary according to the ship size and the anticipated weather conditions that may be encountered on departure. A 145,000 m^3 LNG carrier typically requires approximately 50,000 m^3 (13.2 million gallons), and a future design 250,000 m^3 carrier is estimated to require approximately 97,000 m^3 (25.6 million gallons) of water to proceed on a voyage.

To maintain the hull integrity of the FSRU and the LNG carrier, a constant curtain of water will be directed overboard during LNG transfer from the carrier to the FSRU. Water curtain volumes will be about the same as for the FSRU; 8,718 gallons/hour (33 m^3 per hour) during the cargo transfer time. This is standard industry practice. To prevent the growth of marine organisms, the water will likely be treated with sodium hypochlorite to the same concentration as the intake water for the FSRU.

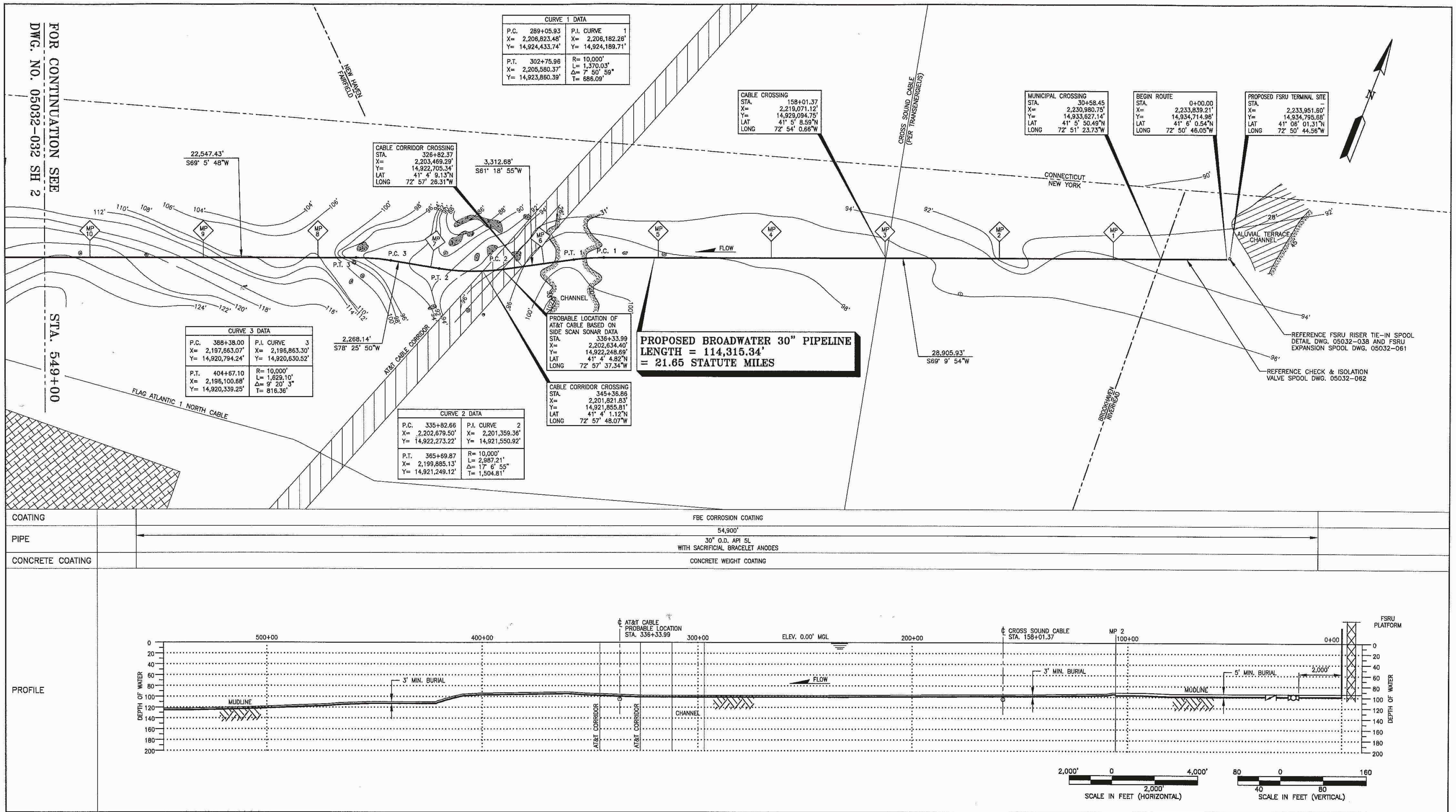
1.3.3 Subsea Connecting Pipeline

1.3.3.1 Overview of Pipeline

The Project will include an approximately 21.7–mile-long, 30-inch outside diameter subsea gas transmission pipeline from the FSRU to a subsea hot tap interconnection on the existing IGTS pipeline crossing of Long Island Sound. Figures 1-9a and 1-9b show the alignment and profile of the proposed pipeline route. Features of the pipeline route are summarized in Table 1-2.

Table 1-2 Subsea Connecting Pipeline Route Features

Location	Description	Water Depth
Mooring Tower	ESD isolation valve, pig launcher, pipeline riser, and subsea-subsurface safety valve (SSSV) umbilical and controls supported by the mooring tower structure	N/A
MP 0.0	Subsea pipeline interconnection with pipeline riser at base of the mooring tower structure, including a remotely controlled subsea-subsurface safety valve (SSSV)	94 ft
MP 0.4	Check and isolation valve assembly	94 ft
MP 3.0	Cross Sound Cable power cable crossing	97 ft
MP 6.4	AT&T telecommunications cable crossing	96 ft
MP 14.0	Begin Stratford Shoal Middle Ground crossing	80 ft
MP 14.5	Minimum water depth along route	54 ft
MP 15.0	End Stratford Shoal Middle Ground crossing	100 ft
MP 17.9	Maximum water depth along route	126 ft
MP 21.7	Pipeline hot tap interconnection with IGTS, including subsea shutdown and isolation valves and a subsea pig receiver. (This location corresponds to IGTS Long Island Sound crossing MP 18.2.)	120 ft



NOTES:

1. SURVEY INFORMATION PROVIDED BY TESLA OFFSHORE, INC., JUNE, 2005.
2. GEODETIC INFORMATION BASED UPON UTM ZONE 18N (GRID UNITS IN FEET), GEODETIC DATUM: NAD 83 CLARKE SPHERIOD 1866.
3. AT&T HAS PROVIDED PCS WITH AN AS-BUILT MAP WHICH HAS ONLY ONE COORDINATE POSITION. HOWEVER, PCS WAS TOLD THAT THE CABLE IS WITHIN THE CHARTED ZONE. DIVER SURVEY WILL BE USED TO LOCATE POSITION OF CABLE PRIOR TO CROSSING.
4. THE CROSS SOUND CABLE LOCATION IS PROVIDED BY TRANSENERGIEUS.

LEGEND

LIGHTERING AREAS
IN-ACTIVE DUMPING GROUNDS
CABLE AREAS
LARGE ROCKS
GRAVEL
MILEPOST

ISSUED FOR CONSTRUCTION PLANNING PURPOSES

REFERENCE DRAWINGS

DRAWING NO.	TITLE	DRAWING NO.	TITLE
TAX BOUNDARY	CREATED BY ERM, PROVIDED BY ECOLOGY AND ENVIRONMENT, INC.	NEW YORK – CONNECTICUT BORDER	www.senate.state.ny.us, CLICK ON BILLS AND LAWS, CLICK ON LAWS OF NEW YORK,
PROJECT AREA	CREATED BY ERM, PROVIDED BY ECOLOGY AND ENVIRONMENT, INC., EDITED BY PROJECT		CHOOSE "STATE", CHOOSE ARTICLE 2, SEE SECTION 2 (CONNECTICUT BOUNDARY)
	CONSULTING SERVICES, INC.	SUB-BLOCK 1	EXCERPT FROM FUNCTIONAL REQUIREMENTS – REV 4 IN APPENDIX D
LIGHTERING AREAS	HARDCOPY REPORT MAPS, PROVIDED BY ECOLOGY AND ENVIRONMENT, INC.	STATE COUNTY BOUNDARY	CREATED BY ECOLOGY AND ENVIRONMENT, INC – DIGITIZED OFF OF USGS TOPO
LIS-100	IROQUOIS GAS TRANSMISSION SYSTEM PIPELINE ALIGNMENT DRAWINGS, KEY MAP,	WRECKS, INACTIVE & ACTIVE DUMPING, CABLE AREAS	NOAA ELECTRONIC CHARTS, 2003 PROVIDED BY ECOLOGY AND ENVIRONMENT
	DRAWING INDEX & GENERAL MAP, REV A, DATED 2-26-91	FLAG TELECOM CABLE	FLAG TELECOM
TABLE 4.2.1-1	IROQUOIS GAS TRANSMISSION SYSTEM PIPELINE ALIGNMENT DWGS, PIPELINE ROUTE COORD., POINT P.I. 1	12354 – 1 OF 1	CROSS SOUND CABLE, THALES GEOSOLUTIONS, MAY 2002, PROVIDED BY TRANSENERGIE US LTD.

REVISIONS

REV.	DATE	DESCRIPTION	BY	CHK'D	ENG	APP
A	5-25-05	PRELIMINARY, FOR COMMENT, NOT FOR CONSTRUCTION	J.E.F.	J.H.R.	J.H.R.	T.O.
B	5-27-05	PRELIMINARY, FOR COMMENT, NOT FOR CONSTRUCTION	J.E.F.	J.H.R.	J.H.R.	T.O.
C	7-7-05	PRELIMINARY, FOR COMMENT, NOT FOR CONSTRUCTION	J.E.F.	J.H.R.	J.H.R.	T.O.
D	7-26-05	ISSUED FOR CONSTRUCTION PLANNING PURPOSES	J.E.F.	J.H.R.	J.H.R.	T.O.
E	8-16-05	ISSUED FOR CONSTRUCTION PLANNING PURPOSES	J.E.F.	J.H.R.	J.H.R.	T.O.

BROADWATER
BROADWATER ENERGY

DRAWN BY J.E.F.	DATE 5-11-05		
CHECKED BY J.H.R.	DATE		
DRAFT. SUP.	DATE		
ENGR. J.H.R.	DATE		
AFE#	VALVE SECTION		
FILE NO. 05032-032 SH 1,2.dwg	SCALE 1"= 2,000'		

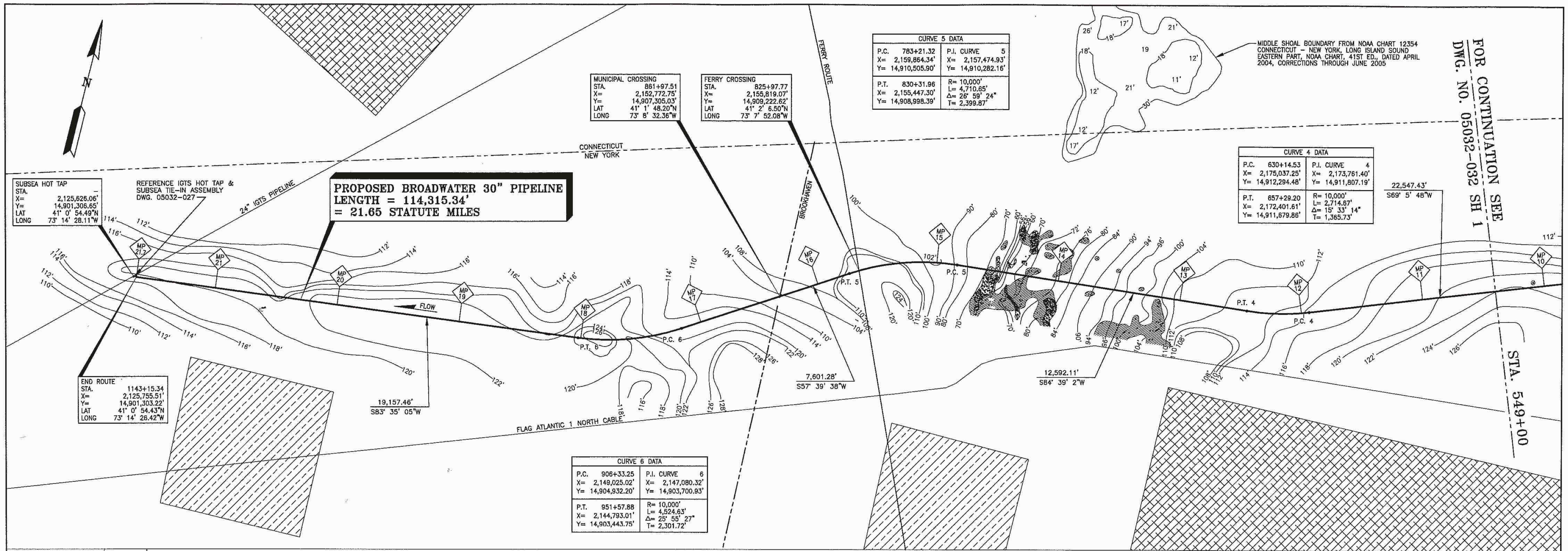
BROADWATER ENERGY
30" O.D. PIPELINE
ALIGNMENT AND PROFILE
LONG ISLAND SOUND, NEW YORK

DWG. NO.: 05032-032 SH 1

REVISION E

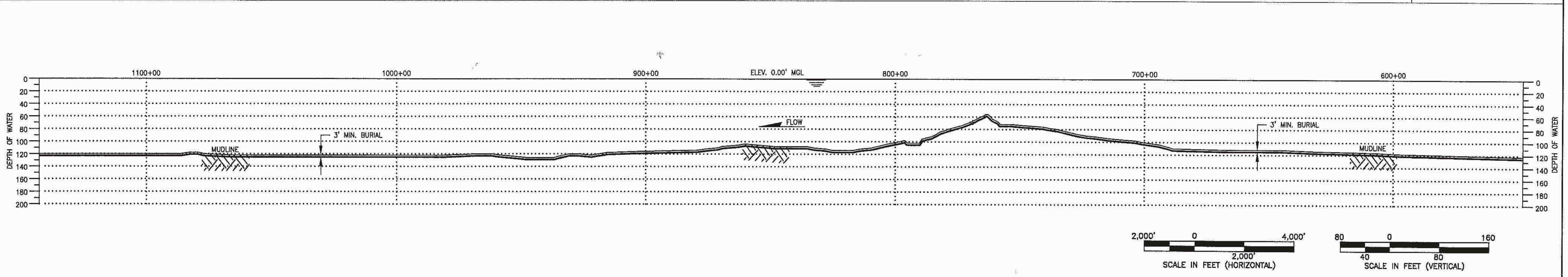
08-15-05 18:27 05032 14 J.E.F.

BW000692



COATING		FBE CORROSION COATING
PIPE		59,415.34' 30" O.D. API 5L WITH SACRIFICIAL BRACELET ANODES
CONCRETE COATING		CONCRETE WEIGHT COATING

PROFILE



NOTES:

1. SURVEY INFORMATION PROVIDED BY TESLA OFFSHORE, INC., JUNE, 2005.
2. GEODETIC INFORMATION BASED UPON UTM ZONE 18N (GRID UNITS IN FEET), GEODETIC DATUM: NAD 83 CLARKE SPHERIOD 1866.

LEGEND

LIGHTERING AREAS
IN-ACTIVE DUMPING GROUNDS
CABLE AREAS
LARGE ROCKS
GRAVEL
MILEPOST MP 19

ISSUED FOR CONSTRUCTION PLANNING PURPOSES

REFERENCE DRAWINGS

DRAWING NO.	TITLE	DRAWING NO.	TITLE
TAX BOUNDARY	CREATED BY ERM, PROVIDED BY ECOLOGY AND ENVIRONMENT, INC.	NEW YORK – CONNECTICUT BORDER	www.senate.state.ny.us, CLICK ON BILLS AND LAWS, CLICK ON LAWS OF NEW YORK,
PROJECT AREA	CREATED BY ERM, PROVIDED BY ECOLOGY & ENVIRONMENT, INC., EDITED BY PROJECT CONSULTING SERVICES, INC.		CHOOSE "STATE", CHOOSE ARTICLE 2, SEE SECTION 2 (CONNECTICUT BOUNDARY)
FERRY ROUTE	ESRI STREETMAP DATA, 2001	SUB-BLOCK 1	EXCERPT FROM FUNCTIONAL REQUIREMENTS – REV 4 IN APPENDIX D
LIGHTERING AREAS	HARDCOPY REPORT MAPS, PROVIDED BY ECOLOGY AND ENVIRONMENT, INC.	STATE COUNTY BOUNDARY	CREATED BY ECOLOGY AND ENVIRONMENT, INC – DIGITIZED OFF OF USGS TOPO
LIS-100	IROQUOIS GAS TRANSMISSION SYSTEM PIPELINE ALIGNMENT DRAWINGS, KEY MAP,	WRECKS, INACTIVE & ACTIVE DUMPING, CABLE AREAS	NOAA ELECTRONIC CHARTS, 2003 PROVIDED BY ECOLOGY AND ENVIRONMENT
	DRAWING INDEX & GENERAL MAP, REV A, DATED 2-26-91	FLAG TELECOM CABLE	FLAG TELECOM
TABLE 4.2.1-1	IROQUOIS GAS TRANSMISSION SYSTEM PIPELINE ALIGNMENT DWGS, PIPELINE ROUTE COORD., POINT P.I. 1	12354 – 1 OF 1	CROSS SOUND CABLE, THALES GEOSOLUTIONS, MAY 2002, PROVIDED BY TRANSENERGIE US LTD.

REVISIONS

REV.	DATE	DESCRIPTION	BY	CHK'D	ENG	APP
A	5-25-05	PRELIMINARY, FOR COMMENT, NOT FOR CONSTRUCTION	J.E.F.	J.H.R.	J.H.R.	T.O.
B	5-27-05	PRELIMINARY, FOR COMMENT, NOT FOR CONSTRUCTION	J.E.F.	J.H.R.	J.H.R.	T.O.
C	7-7-05	PRELIMINARY, FOR COMMENT, NOT FOR CONSTRUCTION	J.E.F.	J.H.R.	J.H.R.	T.O.
D	7-26-05	ISSUED FOR CONSTRUCTION PLANNING PURPOSES	J.E.F.	J.H.R.	J.H.R.	T.O.
E	8-16-05	ISSUED FOR CONSTRUCTION PLANNING PURPOSES	J.E.F.	J.H.R.	J.H.R.	T.O.

BROADWATER
BROADWATER ENERGY

DRAWN BY J.E.F.	DATE 5-11-05	
CHECKED BY J.H.R.	DATE	
DRAFT. SUP.	DATE	
ENGR. J.H.R.	DATE	
AFE#	VALVE SECTION	
FILE NO. 05032-032 SH 1,2.dwg	SCALE 1"= 2,000'	

BROADWATER ENERGY
30" O.D. PIPELINE
ALIGNMENT AND PROFILE
LONG ISLAND SOUND, NEW YORK

DWG. NO.: 05032-032 SH 2
REVISION E

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1.3.3.2 Design Codes and Standards

The pipeline system will be designed in accordance with Part 192, Title 49, "Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards" (latest edition) of the Code of Federal Regulations (CFR). Provided all minimum federal safety standards have been met, ASME B31.8 "Gas Transmission and Distribution Piping Systems" will be used to supplement the requirements of 49 CFR, Part 192. Codes from the following organizations are incorporated into the design as applicable:

- American Gas Association (AGA)
- American National Standards Institute (ANSI)
- American Petroleum Institute (API)
- American Society of Mechanical Engineers (ASME)
- Instrument Society of America (ISA)
- International Standards Organization (ISO)
- Manufacturers Standardization Society of the Valve and Fitting Industry (MSS)
- National Association of Corrosion Engineers (NACE)
- Occupational Safety and Health Administration (OSHA)
- Uniform Building Code (UBC)

1.3.3.3 Pipeline Material Specifications

The pipeline is in a Class 1 Location as defined by 49 CFR Part 192. The pipeline material will be high strength steel manufactured in accordance with the latest edition of API 5L Standard Specification for Line Pipe. The wall thickness of the 30-inch-diameter pipeline will be designed to resist the combined loads that may be experienced during pipeline installation, testing, and normal operation. Limitations imposed by regulatory requirements and design codes also will be accounted for in the pipeline design. The pipeline will be designed for a maximum allowable operating pressure (MAOP) of 1,440 psig. Pipeline fittings will conform to ANSI 900 specifications, and the line pipe will be of one of the following or comparable material specifications:

- 30" O.D. x 0.720" W.T. API 5L Gr. X60; or
- 30" O.D. x 0.665" W.T. API 5L Gr. X65; or
- 30" O.D. x 0.617" W.T. API 5L Gr. X70.

1.3.3.4 Corrosion Protection

To resist corrosion of the pipeline exterior, the pipeline will be externally coated with a coating material such as fusion-bonded epoxy.

In addition to an external coating, the pipeline will incorporate sacrificial anodes with a design life of a minimum of 30 years. This secondary cathodic protection system will supplement the pipeline coating should it be damaged during installation or operation. An insulating joint will be installed in the IGTS spool piping to isolate the IGTS pipeline cathodic protection from the Broadwater pipeline cathodic protection. Also an above water isolation flange kit will be considered in the riser and topside design of the YMS.

1.3.3.5 Concrete Weight Coating

Weight coating required for negative buoyancy and on-bottom stability will be steel reinforced concrete (140 to 205 pounds per cubic foot densities, as required) applied over the fusion-bonded epoxy (FBE) corrosion coating. During the detail design phase the concrete coating thicknesses will be determined through an on bottom stability analysis, and the use of adhesive between FBE coating and concrete weight coating for additional adhesion during lay operations will be evaluated. Preliminarily the thickness of the concrete weight coating is approximately 3 inches.

The concrete weight coating will be applied at an existing off-site concrete coating plant at a location to be determined during detailed design. The concrete weight coated line pipe will then be transported to the region to a stockpile and transhipment site where it will be stored awaiting commencement of construction.

1.3.3.6 Pipeline Emergency Shutdown and Isolation Systems

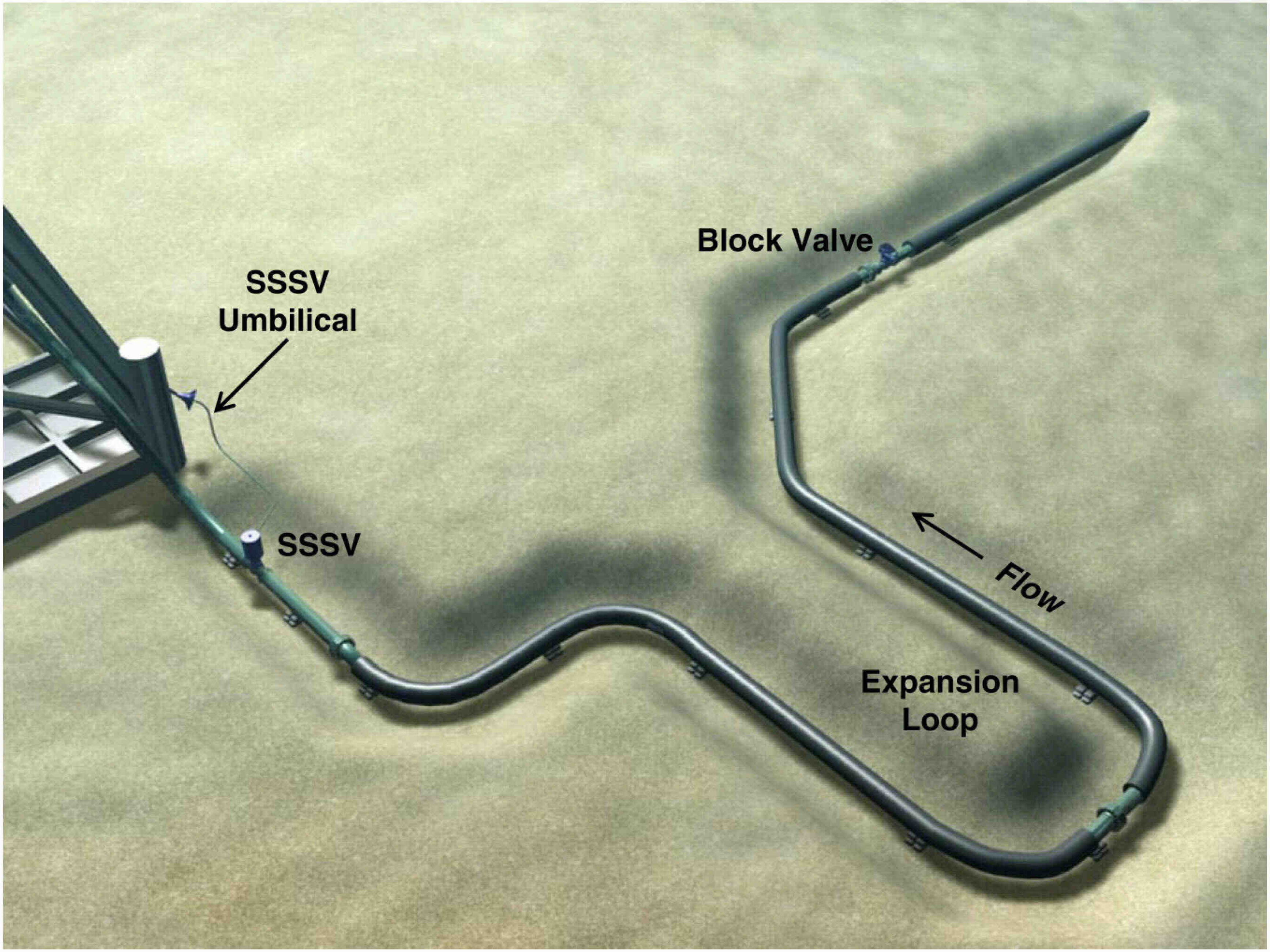
The pipeline will connect the FSRU to the IGTS pipeline and will include a number of valves that are required for isolation and installation. On the YMS mooring tower an ESD and isolation valve will be provided upstream of the pipeline riser. The balance of the ESD and isolation systems on the pipeline will be comprised of various valves packaged into pipeline spools that will be fabricated off site and installed by the pipeline contractor.

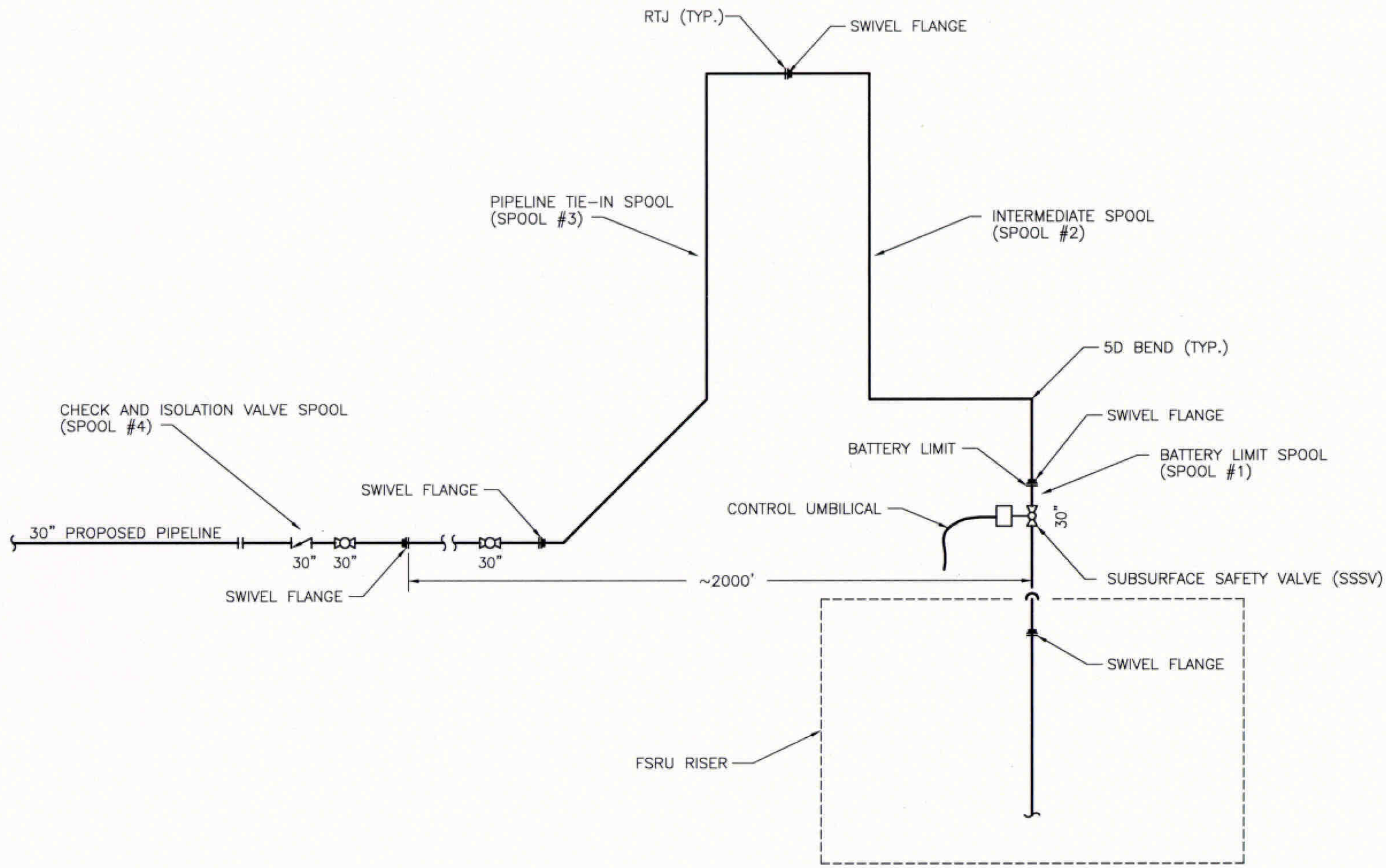
The subsea connection between the Broadwater pipeline and the 30-inch-diameter riser on the YMS is depicted on Figure 1-10 and shown in a schematic on Figure 1-11. It will consist of four spools, of which two will provide an approximately 80 ft x 40 ft expansion loop (design for warm gas conditions is described in Section 1.3.3.8), and the following two will comprise the subsea shutdown and isolation systems at the pipeline begin-of-line:

- Subsea Subsurface Safety Valve and umbilical: The battery limit spool incorporates a Subsea-Subsurface Safety Valve (SSSV). The SSSV will be a 30-inch full-opening ball valve fitted with an actuator and an umbilical connection. The SSSV will be controllable from the YMS and from the FSRU for remote, automatic, and emergency shut down (ESD) activation.

- Block valve: The pipeline tie-in spool incorporates a gear-operated maintenance valve that normally will be open and will require manual actuation by diver to close it.

A check and isolation valve spool will be installed approximately 2,000 feet downstream of the YMS riser. These valves are included in the design to isolate the section of pipeline adjacent to the FSRU from the rest of the Broadwater pipeline. The check valve will automatically contain gas downstream without manual intervention should there be a failure in the pipeline system inside the weathervaning radius of the FSRU. The isolation valve will require manual actuation by diver to close it.


SSSV
Umbilical
Block Valve
SSSV
Flow
Expansion
Loop



FSRU SUBSEA TIE-IN SCHEMATIC

SCALE: N.T.S.

NOTES:

1. 30" CHECK VALVE TO BE PIGGABLE.

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BROADWATER BROADWATER ENERGY	PROJECT CONSULTING SERVICES, INC. 3300 WEST ESPLANADE AVE., S., SUITE 500 METAIRIE, LA 70002-7406 (504) 833-5321 Fax (504) 833-4940 www.projectconsulting.com	FSRU SUBSEA TIE-IN SCHEMATIC	DRAWN BY: J.E.F. CHK'D. BY: J.H.R. DATE: 5-31-05 APPRV. BY: T.O. DWG. NO. 05032-037 REV E

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The connection between the Broadwater pipeline and the 24-inch-diameter IGTS pipeline, depicted on Figure 1-12 and shown in schematic form on Figure 1-13, will consist of three spools. The hot tap assembly and components will include a ball valve and a ring-type joint (RTJ) flange (with blind). This RTJ flange will be the connecting point for the spools that connect the Broadwater pipeline to the IGTS pipeline. The hot tap connecting spool contains the subsea shutdown and isolation systems at the pipeline end of line. This "T" shaped spool incorporates a check valve, which will automatically isolate the Broadwater pipeline from the IGTS pipeline without manual intervention by preventing a backflow condition from the IGTS pipeline, as well as a diver-operated block valve that is normally open. In addition, the pipeline tie-in spool incorporates a gear-operated maintenance valve that normally will be open and will require manual actuation by diver to close it.

In the event it is necessary to evacuate the pipeline and the IGTS pipeline is not available for use, gas in the connecting pipeline will be directed to the flare stack on the FSRU.

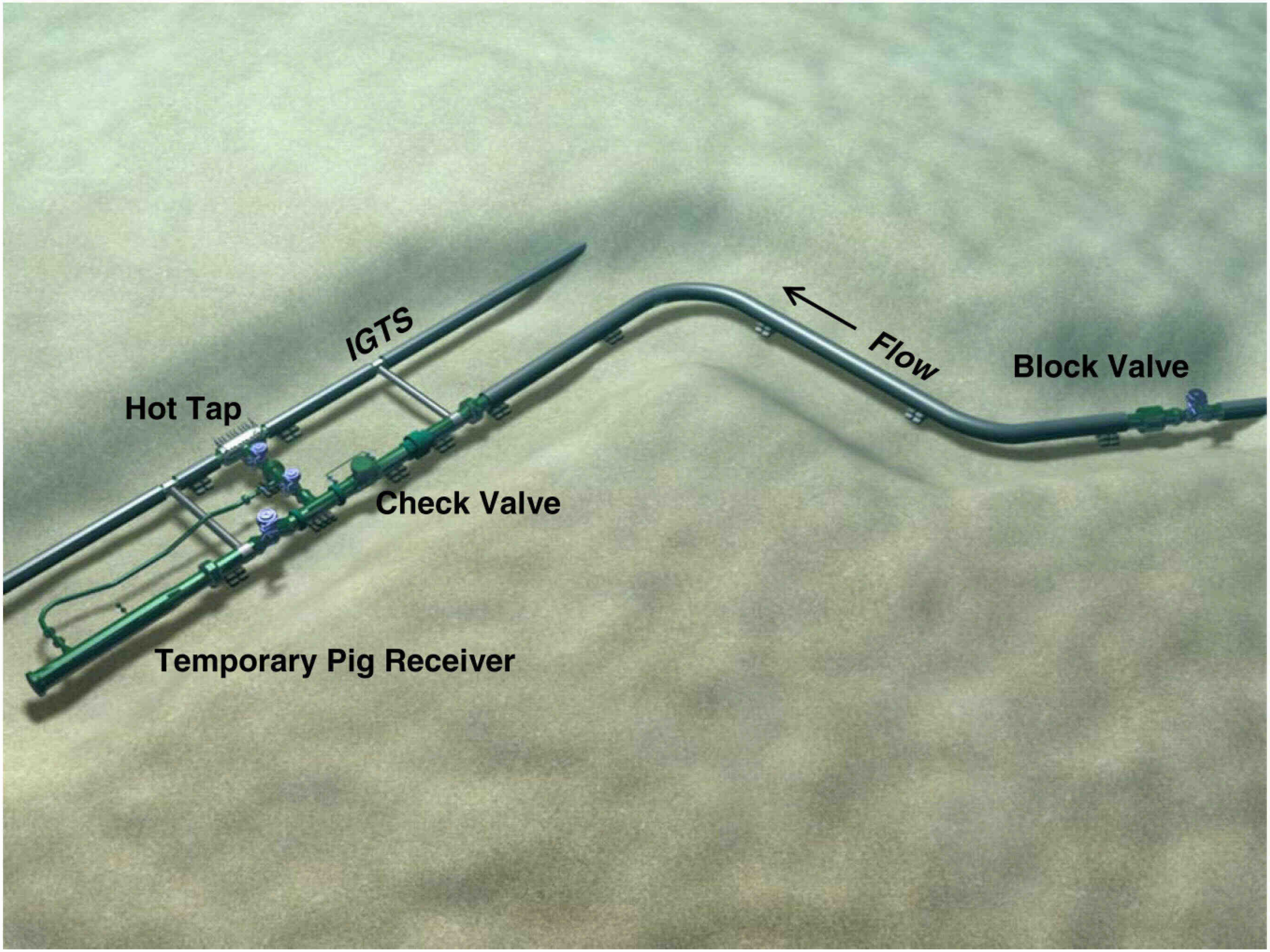
1.3.3.7 Pigging Facilities

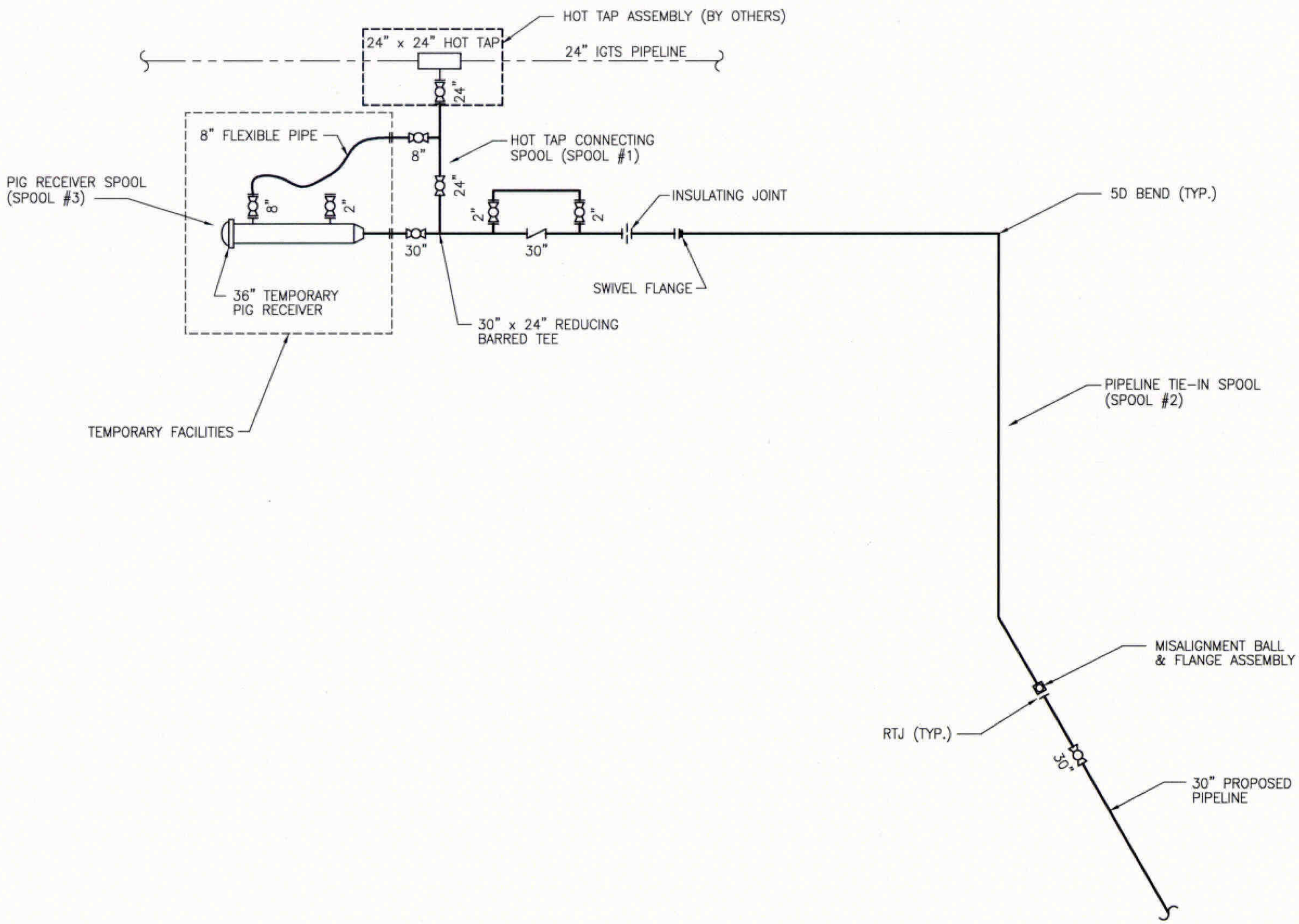
Pigging traps will be constructed for the various pigging operations required, ranging from post-construction cleaning and caliper pigging to the periodic operational maintenance running of intelligent pigs for pipeline integrity assessment. Traps are designed in accordance with applicable codes and regulations for fittings and connections to the pipeline. The launching trap will be placed on the mooring tower. The receiving trap will be a temporary trap installed near the subsea connection to the IGTS pipeline.

The IGTS Hot Tap Connecting Spool shown on Figures 1-12 and 1-13 will contain a flange connection for attaching the Pig Receiver Spool. The flange will normally have a blind attached that will only be removed when a pigging operation is scheduled. The receiver will be mobilized with a support diving crew when the pigging operations are performed. The receiver will be lowered to the tie-in spool, flanged into position and will receive the pig. Prior to removing the blind on the pig receiver flange, a pollution dome will be installed over the connection area to capture any hydrocarbon leaks that may occur during operation. During the pigging operation a NPS 24 valve that is part of the subsea connection assembly to the IGTS pipeline will be closed to direct gas flow through the receiver barrel. An 8-inch flexible pipe will be connected from the pig receiver to the NPS 24 valve assembly to allow the gas to continue through the pipeline as the pig is being received.

1.3.3.8 Pipeline Depth of Cover

The pipeline will be lowered below the seabed along its entire length such that the top-of-pipe is a minimum of three feet below the pre-disturbed natural bottom, wherever sediment conditions permit. Settling of the trench walls and natural sedimentation will be allowed to in-fill the excavated trench for the majority of the pipeline between MP 2.0 and MP 21.7.


IGTS
Flow
Block Valve
Hot Tap
Check Valve
Temporary Pig Receiver



IGTS SUBSEA TIE-IN SCHEMATIC

SCALE: N.T.S.

NOTES:

1. 30" CHECK VALVE TO BE PIGGABLE.

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			DATE: 4-14-05	APPRV. BY: T.O.
			DWG. NO. 05032-022	REV D

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If the minimum depth of cover cannot be achieved based on the sediment conditions and Broadwater determines that supplemental pipeline protection is needed, rock, concrete mats, or sand bags may be utilized to provide protection and pipeline stability based on site-specific conditions encountered at the time of construction. Rock and sand bag installation will be accomplished using drop tubes or similar means to ensure correct placement within the pipeline trench and over the pipeline. Concrete mat installation will be diver-assisted to ensure adequate coverage of the pipeline. The following locations will have additional protection and/or stabilization measures:

- The two cable crossings may need concrete mats placed over the installed pipeline where the pipeline bridges over the cable and if the top of the pipeline is less than three-feet below the natural sea-bed; and

- The tie-in locations at the FSRU and IGTS locations will have protective structures and/or protection materials in addition to some rock back-fill and sand/cement bags or grout bags.

Protective structures, if used, will be cage-like structures placed over the top of all or some of the subsea valve assemblies in the pipeline. The final requirements, design, and dimensions will be determined in the detailed design phase. The cage-like structures will be constructed of steel tubing and plate, and either steel or fiberglass grating materials. They will have the following approximate plan dimensions:

- IGTS tie-in assembly (including check valve, block valve, and associated bypass valves, blind flange, tie-over valves and hot tap assembly): 52 ft. x 32 ft.

- SSSV valve at tie-in with YMS riser: 17 ft. x 15 ft.

- Block valves at tie-ins with YMS riser and IGTS pipeline: 17 ft. x 15 ft.

- Block and check valve assembly at MP 2.0: 30 ft. x 15 ft.

The protective structures, where used, will be installed by a DSV or other construction support vessel during installation of the various spools. At a height of about 10 feet they will protrude about 3 feet above natural seabed level except for the valves at the IGTS tie-in, where the IGTS pipeline was found to have about 8 feet of cover. Sand/cement or sand only bags can be used to transition the side slopes of the cage-like structures and, if necessary, concrete mattresses can be laid across the top portion of the cage to cover the access hatches for burial protection.

Design for Warm Gas Conditions

The send-out gas stream from the FSRU will be warm. Vaporized LNG will enter the subsea connecting pipeline at temperatures between approximately 90 ^{o}F and 120 ^{o}F to satisfy downstream IGTS requirements. To prevent excessive deflections of the subsea connecting pipeline due to thermal expansion, a pipeline expansion loop will be incorporated into the design immediately downstream of the SSSV (*see* Figures 1-10 and 1-11). In addition, to constrain and stabilize the subsea connecting pipeline over approximately the first 2 miles from the FSRU (MP 0.0 to MP 2.0) it will be lowered below the seabed to a depth of cover of five feet then mechanically backfilled.

1.3.3.9 Compatibility and Integration with Iroquois Gas Transmission System

The Project is designed to increase the availability of natural gas to the New York and Connecticut markets through an interconnection with IGTS. The interconnection will be located subsea at MP 18.2 of the Iroquois Long Island Sound crossing.

IGTS Expansion Requirements

The Project is designed to take advantage of existing pipeline capacity in the southern region of the IGTS. No incremental pipeline looping or compression facilities on the current IGTS pipeline system are foreseen. Hydraulic analysis of the Iroquois system by Broadwater demonstrates that the existing pipeline can accommodate a wide range of pipeline system flows that, in turn, can accommodate the Broadwater gas input without additional looping or compression.

Downstream metering facilities may be required on the IGTS to affect deliveries to customers at new delivery points. None of those requirements have been identified to date. To the extent that these facilities may be required by IGTS' customers, impacts from the addition of metering or other minor facilities would not be expected to be significant and can be addressed when and if IGTS determines that those facilities are required.

Pipeline Design

The IGTS pipeline across Long Island Sound has the following material specification: 24" O.D. x 0.576" W.T. API 5L Gr. X60.

In its letter to the FERC dated October 7, 2005, IGTS stated that its pipeline from the Connecticut shore line to its Northport Sales Meter Station is designed to allow for a potential future increase above the current MAOP of 1,440 psig, subject to receipt of any regulatory approvals that may be necessary.

The Broadwater subsea connecting pipeline will be tested and qualified for an MAOP of 1,440 psig to match the current MAOP of the existing IGTS pipeline of 1,440 psig. The design of the Broadwater pipeline fittings and line pipe wall thickness will conform to the design philosophy utilized by IGTS. The increased design margin that results from adoption of the IGTS pipeline design standard provides an extra measure of public safety for the Broadwater subsea connecting pipeline in its Class 1 Location.

The initial design of the IGTS pipeline did not contemplate the direct connection of 1.0 bcfd of natural gas from LNG, or any other supply source, in the immediate Long Island and New York City region. By connecting the Broadwater FSRU and its LNG supply directly to the offshore portion of the IGTS pipeline, IGTS will benefit from an increase in throughput in the IGTS pipeline across the Sound, without a need for increase in the

MAOP of the IGTS pipeline. A further benefit to IGTS is that, with the Broadwater Project attached, the need for new or expanded compression on the IGTS system onshore in Connecticut, or at any other point on its system, to be able to utilize an increase in the pipeline's MAOP, is potentially eliminated.

Gas Control

Day-to-day operations of the Broadwater FSRU and subsea connecting pipeline and of the IGTS pipeline will be integrated and coordinated. The FSRU command and control facility will exercise active control of gas send-out operations and emergency shutdown procedures on the FSRU and YMS, including operation of the SSSV on the subsea connecting pipeline at the base of the YMS mooring tower. The existing gas control center for the IGTS system in Shelton, Connecticut, will be in continuous, uninterrupted communication with the command and control facility on the FSRU and will monitor pipeline system conditions and deliveries into the subsea connecting pipeline system.

Gas Quality and Measurement

The Broadwater facility will manage send-out gas properties, including gas quality and heating value (*see* also Section 1.3.2.5.). Broadwater will meet the gas quality limits stipulated in the IGTS FERC Gas Tariff, as those tariff limits may be amended from time to time. The send-out natural gas stream will be sampled and measured on a continuous basis to ensure it meets IGTS' gas quality specifications at all times before it is transferred from the FSRU to the subsea connecting pipeline. An on-line gas chromatograph system on board the FSRU will provide continuous quantitative analysis of the vaporized natural gas. It will quantify the concentrations of the main natural gas components for the purpose of gas accounting, calculation of calorific value (heating value), and reference density for fiscal purposes and for check of gas quality conformity according to limits stipulated in the IGTS FERC Gas Tariff. Broadwater will provide IGTS with the ability to monitor the quality of the gas entering the Broadwater subsea connecting pipeline. Further, IGTS will itself be able to monitor the quality of the commingled gas stream in its system at onshore sampling and measurement locations through the addition of gas chromatographs.

Volumetric Measurement

Locating the Broadwater metering facilities on board the FSRU is significantly preferable in terms of environmental impact to building new metering facilities in Long Island Sound at the IGTS interconnect. Modeling and measurement tools capable of determining gas loss after measurement on the FSRU but before interconnection with the IGTS will be utilized as needed. Furthermore, the ability to measure gas volumes from the FSRU combined with aggregate volumes entering and exiting Long Island Sound on the IGTS will provide an adequate means to account for gas volumes.

Pipeline Emergency Shutdown and Isolation

Both the Broadwater and IGTS subsea pipelines include equipment features designed to increase the overall safety of the system and protect the public from a potential failure due to accidents or natural catastrophes.

The Broadwater pipeline will be equipped with a buried SSSV at the base of the pipeline riser and will be remotely controlled from the YMS and from the FSRU command and control facility in an emergency. A check and isolation valve assembly will be installed approximately 2000-feet downstream of the riser and will automatically isolate the section of pipeline adjacent to the FSRU from the rest of the Broadwater pipeline and contain gas downstream and prevent backflow should there be a failure in the pipeline system at any point upstream.

The connection between the Broadwater pipeline and the IGTS pipeline will incorporate a subsea shutdown and isolation system including a check valve. The check valve will isolate the Broadwater pipeline from the IGTS pipeline by preventing backflow from the IGTS pipeline. This will enable the IGTS pipeline to continue operating in the unlikely event of a shutdown of the Broadwater subsea connecting pipeline in an emergency.

Finally, as a fail safe, the integrated system of existing onshore remote control mainline block valves at each side of IGTS pipeline crossing of Long Island Sound together with the Broadwater SSSV will allow the combined Broadwater and IGTS subsea pipeline systems in the Sound to be quickly shut down in an emergency. This does not, however, imply that these systems must operate together in the event of a requirement to shut down flows from the Project. Broadwater intends to work with IGTS to develop an operating philosophy that will address potential interruptions in operations.

1.4 LAND REQUIREMENTS

1.4.1 Project Requirements

The Project will be entirely located in the New York State waters of Long Island Sound. The FSRU will be located approximately 9 miles off the New York shoreline and approximately 10 miles from the Connecticut shoreline. By selecting an FSRU as the technology for the receiving terminal, Broadwater will be able to avoid adverse environmental impacts that would be associated with using an offshore gravity-based structure or siting the facility onshore and requiring significant dredging and/or pier development to accommodate LNG carriers. Onshore facilities are discussed in a separate volume.

The FSRU will be moored in place using a YMS that will be permanently attached to the tower structure with tubular legs that are pile-driven into the Sound floor to a depth of 230 ft (70 m).

A safety and security zone will be established around the FSRU location to provide additional safety and security of the facility. The nature and extent of this zone will be determined by the USCG.

The undersea connecting pipeline will require approximately 21.7 miles of new 30-inch pipeline to connect the FSRU with the existing subsea section of the IGTS pipeline in Long Island Sound. A right-of-way lease from the New York State Office of General Services (NYSOGS) is expected to be obtained for both the mooring tower and the connecting pipeline. This Project proposes no onshore crossing for the pipeline.

It is anticipated that the subsea connecting pipeline will be constructed within a 300-foot construction right-of-way that will generally encompass the maximum lateral width of disturbance due to trench excavation. The actual width of disturbance from the pipelaying and installation activities is anticipated to be approximately 75 feet, encompassing both the pipeline trench and adjacent spoil piles generated during the subsea plowing of the seabed to install the pipeline. Pipelaying and installation will require the use of anchored vessels. A wider, approximately 4,000-foot-wide construction corridor will be required to allow placement of anchors to stabilize the construction vessels.

Following installation of the pipeline, a permanent 30-foot right-of-way centered on the as-built pipeline location will be established for operation of the facility. The temporary and permanent easements will be granted by the New York State Office of General Services. Specific land use requirements for the Project are presented in Resource Report 8 (Land Use, Recreation, and Aesthetics).

1.5 GENERAL DESCRIPTION OF CONSTRUCTION AND SITING PROCEDURES

1.5.1 FSRU Construction

The FSRU will be constructed at a qualified shipyard and will be towed to the site in Long Island Sound for final placement and installation. The hull will be built in pre-assembled units (blocks), which will have equipment and outfitting installed during construction. The blocks will be built in on-site workshops and will be assembled in a large dry dock at the shipyard.

During the transit from the shipyard to the proposed site, the FSRU will exchange ballast prior to the FSRU entering Long Island Sound. This will prevent the unintended introduction of foreign species into the aquatic habitat of the Sound. Ballast water management will be in accordance the International Convention for the Control and Management of Ships Ballast Water and Sea Water.

1.5.2 Construction of Tower Structure for YMS and Subsea Connecting Pipeline

1.5.2.1 Off-Site Fabrication

The tower structure is constructed in three main segments (jacket, topsides and mooring yoke), each of which is towed and sequentially installed on site before FSRU hook up, send-out pipeline connection and Project commissioning. The location of tower fabrication will be determined during the contracting stage. This location may be overseas at one or more of various established construction facilities.

1.5.2.2 On-Site Installation

The tower system includes a steel jacket structure that is fixed to the seabed by means of steel piles. The offshore installation work for the FSRU and pipe tower system will consist of installing the steel jacket on the seabed, driving the piles through the jacket pile guides into the seabed, fixing the piles to the jacket, attaching the topsides, connecting the mooring yoke to the jacket, hooking up the FSRU, mechanical completion of the riser and connecting the pipeline to the YMS.

The pile driving methods and arrangements for the jacket installation are subject to a geotechnical investigation and site survey. Sediment samples will be taken to a depth of 80 m and will form the basis of pile driving approach. It is not expected that any drilling will be required unless hard rock is found. As such, the pile driving will be carried out by hydraulic hammer. This will be completed from the water surface and entails a follower to be attached to the upper portion of the pile for driving. Depending on the sediment condition, the pile may be inserted in sections and welded to form a single pile length. The method requires a crane barge for jacket lifting, equipment storage and pile driving hydraulic hammer and power pack. The barge will be supported by three tugs for its positioning and fixing. Station keeping will be achieved by anchoring to the sea floor in a square anchor pattern of approximately 650 ft (200 m) side distance. This will be the approximate footprint required for tower installation. Two diving tenders will also be required on site throughout for guiding underwater operations. For installation of the jumpers, a dynamically positioned (DP) capable supply boat is anticipated.

After piling, the mooring system jacket will be installed and connected with the piles. After adjusting verticality, the annular spaces between the piles and guides will be injected with grout. The injection is carried out from the surface via flexible hoses and is controlled in situ by a diver or ROV. Procedures and materials will comply with API RP2 and be approved by the Classification Society. Very little or no grout will escape from the annular space, as injection is halted when the space is filled.

A proprietary grout widely used in the offshore industry, such as Ducorit S5 or equivalent, will be employed. This cement-based product, which consists of various minerals, is biodegradable and will have no environmental impact. The aggregates contained in the product will precipitate and other components, including plasticizers, will rapidly return to their original state (e.g., $CaCO_3$, Al_2O_3, SiO_2, and Fe_2O_3) without harm by reacting with water, forming hydroxides and CO_2.

When cured, the product can be considered a form of stone and will not be routinely replaced during the lifetime of the project.

To control stability during lowering of the mooring tower jacket, a shallow frame, or mud mat, is installed at the base of the jacket between the four legs. The mud mat is made of untreated lumber and has the sole purpose of providing stability control during jacket installation. The mud mat will be buried during the installation process by bottom sediments flowing around and through the framing. Sediment from the seabed will flow over the edges of the mud mat as the jacket settles onto the seabed, effectively burying it in the process. While the untreated lumber will remain buried in the sediment and may provide some habitat value, it is not intended as a biological habitat feature.

Other offshore installation work that will relate to the tie-in of the send-out pipeline to the FSRU via a subsea tie-in is described in Section 1.5.3.

Subject to the results of the geotechnical investigation, it is estimated that the full YMS installation will take approximately 29 days, assuming 12 hours operational time per day, with the sequence of activities as shown in Table 1-3.

Table 1-3 YMS On-Site Installation Sequence

Activity	Duration
Setting of jacket	5 days
Pile driving	14 days
Topsides installation	3 days
Mooring Yoke installation	1 day
FSRU Hook up	3 days
Installation of Process Jumpers	3 days
Total	**29 days**

Various vessels will be mobilized into Long Island Sound by the tower system contractor:

- Crane Barge
- Support Barge(s)
- Tugs
- Dive Support Vessel (DSV)
- Personnel Carrier and Utility Launch(es)

The workforce associated with the onsite tower system installation is estimated at 132 personnel of which 64 personnel is estimated as the peak workforce over a duration of 14 days. The workforce will be involved in the following areas:

- Barge crew(s)
- Tug crews
- Divers and dive tender crew
- Crane riggers
- Welders
- Personnel carrier and utility launch(es) crew
- Manufacturer's supervisors and engineers
- Broadwater inspection personnel

For the vast majority of the workforce and time, housing will be on offshore vessels for the duration of the installation. However, hotel accommodation may be required on an ad hoc basis, particularly for transit. Medium- or long-term housing requirements other than the hotel accommodations mentioned above are not expected to be required.

1.5.3 Construction of the Subsea Connecting Pipeline

1.5.3.1 Overview of Pipeline Installation

The subsea connecting pipeline will be laid on the seabed and lowered using conventional underwater installation techniques.

The majority of pipeline will be installed by a lay barge designed for this type of marine construction. It is the main piece of construction equipment that will be utilized. The lay barge has a variety of construction support vessels such as escort vessels, survey vessels, pipe supply barges and tugs, anchor handling tugs, and security, utility and personnel launches. The lay barge provides the work platform for the welding and inspection of the pipe joints (40-foot lengths of pipe) to make one continuous pipeline. The lay barge advances by pulling on mooring anchors and the pipeline is laid on the seabed off a "stinger" at aft end of the lay barge in a continuous operation as more joints of pipe are added. The lay barge will have accommodation for the marine and construction crews to work 24/7 in 8 or 12 hour shifts with associated catering and support facilities.

The secondary pipeline installation vessel will be a DSV. A DSV will be used to install the majority of the various pipeline spools at each end of the pipeline that are not installed by the lay barge, as well as to support any underwater work or inspection requirements. A DSV typically holds station with anchors, or can be dynamically positioned (DPDSV). More information on DSVs and DPDSVs is provided in Section 1.5.3.9.

Upon completion of the pipe-laying operation, the pipeline will be lowered below the seabed along its entire length, wherever sediment conditions permit. In general, pipeline lowering can be accomplished by either pre- or post-trenching of the seabed. Pre-trenching is trenching prior to pipeline lay and is used if the pipeline needs to pass through very stiff material. Post-trenching means that the trenching equipment would remove sediment from the underneath and sides of the pipeline while the pipe lies on the seabed.

1.5.3.2 Pipe Lay

The pipeline will be installed utilizing a purpose built pipeline lay barge or vessel using an installation method known as S-Lay (*see* Figure 1-14). S-lay is a conventional method of installing pipelines in shallow to moderate depth waters. Segments of pipe, "joints," are stored on the lay barge and staged in a preparation area where the ends are beveled and cleaned. As the barge is maneuvered forward on anchors along the planned pipeline centerline in 40-foot steps, the prepared joints are positioned and added to the pipeline with successive welds performed at each of the dedicated welding stations positioned at 40-foot intervals along the barge in a controlled assembly line.

The pipe lay operation will be performed using a conventional anchored laybarge of approximate dimensions of 120 ft x 400 ft x 20 ft with an eight-point (or more) mooring system. The contractor will utilize a suitable and industry accepted means of installing the pipeline after demonstrating the adequacy of the proposed methods/equipment and accompanying pipe lay stress analysis.

TYPICAL PIPELINE LAY BARGE SPREAD

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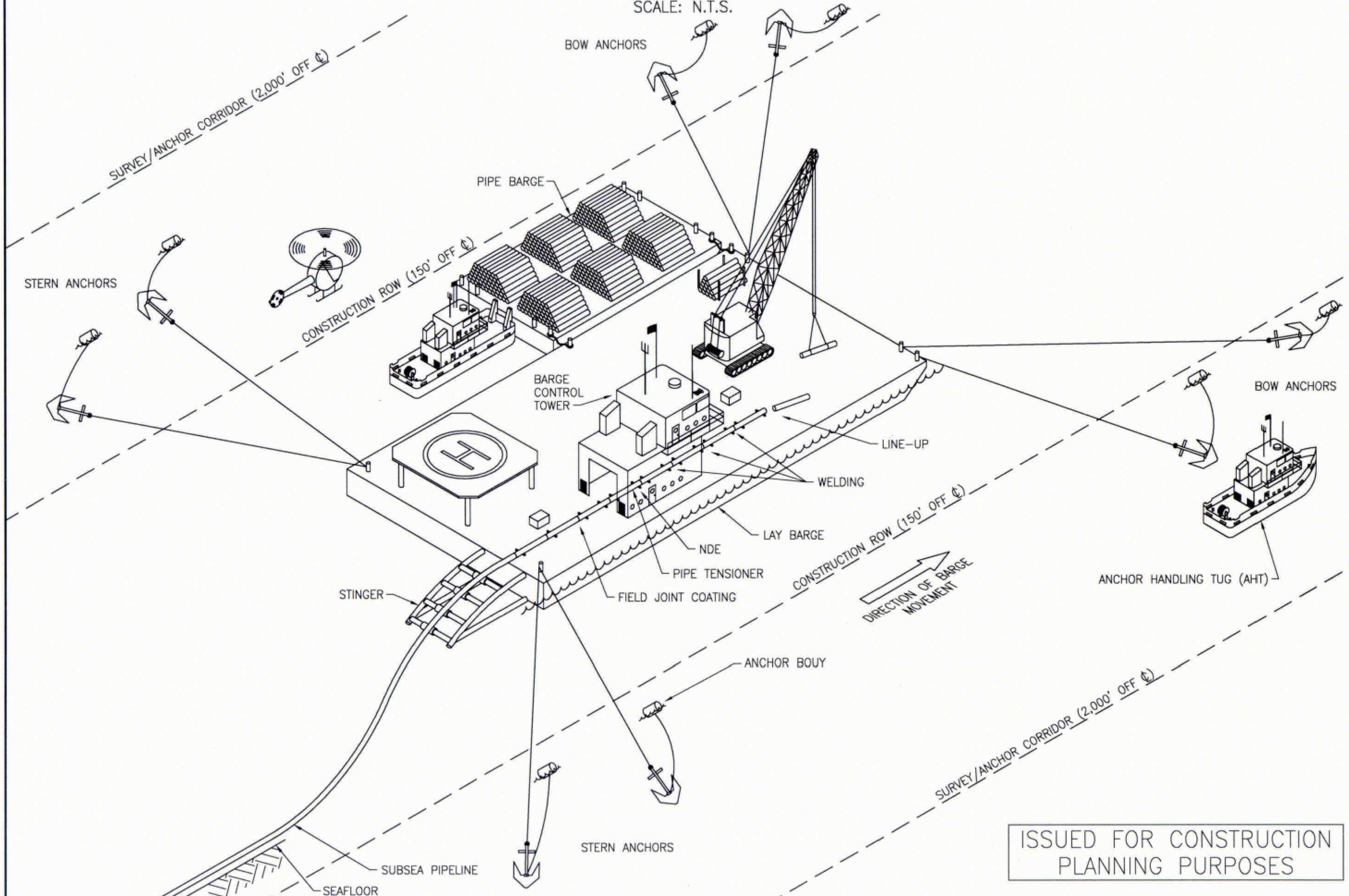

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DRAWN BY:	J.E.F.	CHK'D. BY:	J.H.R.
DATE:	04-13-05	APPRV. BY:	T.O.
DWG. NO.	05032-015	REV	B

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Broadwater will ensure proper anchor placement and put in place measures to detect any unanticipated anchor movement. This will be achieved through careful anchor placement management. The planning of anchor placement in areas of concern will require the development and enforcement of an anchoring plan whereby each anchor placement is coordinated and placed at pre-determined locations. The location of each placed and recovered anchor will be recorded by the surveyors.

Anchor and cable management requirements will be developed during the detailed design stage and incorporated in the construction bid documents for the pipeline. The final anchoring and cable management plan will be developed after a marine pipeline contractor and specific equipment (laybarge and anchor-handling tugs [AHTs]) have been selected. The maximum distance from the centerline of the pipeline to anchor locations during construction will be approximately 2,000 feet (610 m).

AHTs will recover and relocate the barge/vessel anchors during the pipe lay and lowering operations. Where required, the AHTs will modify the anchor lines with mid-line buoys to avoid potential cultural materials or other identified bottom features requiring avoidance.

An average lay rate of 100 joints per 24 hour day working around the clock in shifts is anticipated, with a 25% weather and/or mechanical down time factor. Regional pipe hauling on barges will require a minimum of six assist tugs depending on the distance between the storage yard and the work site.

1.5.3.3 Pipeline Lowering

1.5.3.3.1 Primary Pipeline Lowering Method

Broadwater completed a geotechnical sampling and testing program to characterize the sediments along the pipeline route within the pipeline trench depth. Results are presented in Resource Report 7 (Soils). Generally it was observed that the sediments are mostly fine grained (silts, clays and sands) for over 95% of the route, with coarser material (gravel and cobbles) occurring at the Stratford Shoal Middle Ground. No hard bedrock was observed along the route.

Based on the observed sediment characteristics together with environmental impact concerns, plowing is Broadwater's primary choice for pipeline lowering. Plowing involves passive displacement of sediments by a plowshare as it is pulled forward. Plowing uses pull-barge or vessel force to overcome resistance of the plow being drawn through sediment and it is best suited to consistent silty clay sediments. The pull force is supplied by a special pull barge, or the lay barge itself. Steering is normally accomplished by offset or tow angle of the vessel or by articulated steering depending on the plow design. Monitoring of the depth of cut will be performed by the barge/vessel and occasional diver checks will be made to ensure that all instruments are recording correctly.

Broadwater proposes the post-lay plow method. Post-lay plows ride on the concrete coated pipeline, supported by rollers (*see* Figure 1-15). The plow will excavate a trench below the pipeline previously installed by the lay barge and the pipeline will be lowered into the furrow in the seabed as the plow is pulled ahead by the barge or vessel. Schematics showing typical plowed trench configurations are provided on Figures 1-16 and 1-17.

In Broadwater's pipeline construction plan and impact assessment it is assumed that a conventional anchored lay barge will be used to accomplish pipe lay and pipeline lowering. Information on the sediment impacts of pipeline installation can be found in Resource Report 7 (Soils) and Resource Report 2 (Water Use and Quality). Benthic effects are provided in Resource Report 3 (Fish, Vegetation, and Wildlife).

Multiple passes of the plow may be necessary to achieve the required depth of burial if hard-bottom areas are encountered. For most of the pipeline route it is expected that a single pass of the plow will lower the pipeline to the required depth. However, previous experience with the lowering of pipelines of similar or larger diameter suggests that Broadwater can expect an infrequent reduction in this lowering depth. Broadwater's pipeline construction plan conservatively contemplates two complete passes of the plow.

The expected geometry of the trench is based on an angle of repose of thirty-five degrees (35°). The multi-pass plow will clear the excavated material to a sufficient distance away from the trench to prepare the seabed for another pass. For an approximate 21.7 mile pipeline length the width of seabed disturbance at the top of the trench will be about 25 feet (not including spoil piles adjacent to the trench) and the total area of disturbance at the top of the trench will be about 67 acres (not including spoil piles adjacent to the trench).

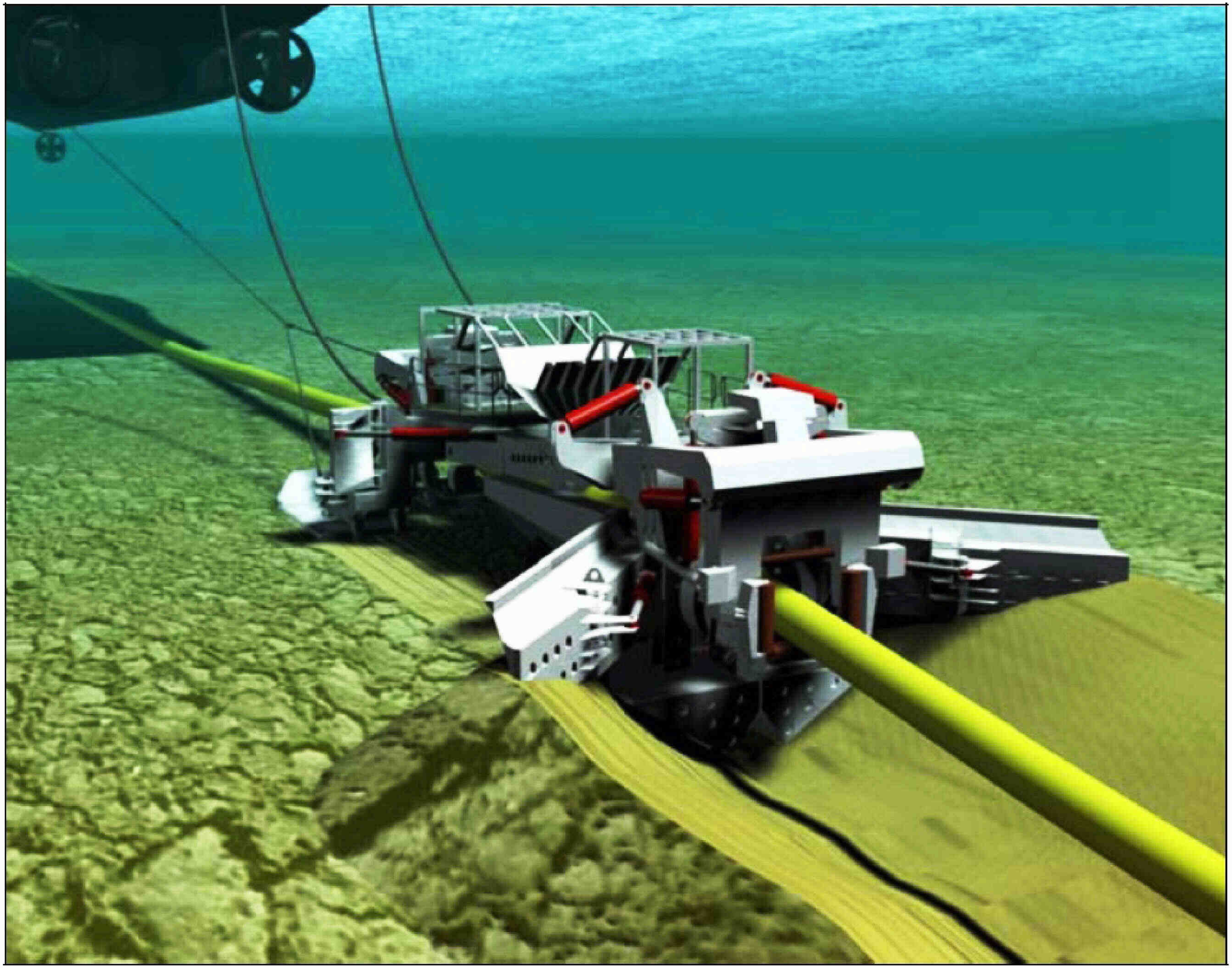
1.5.3.3.2 Cable Crossings

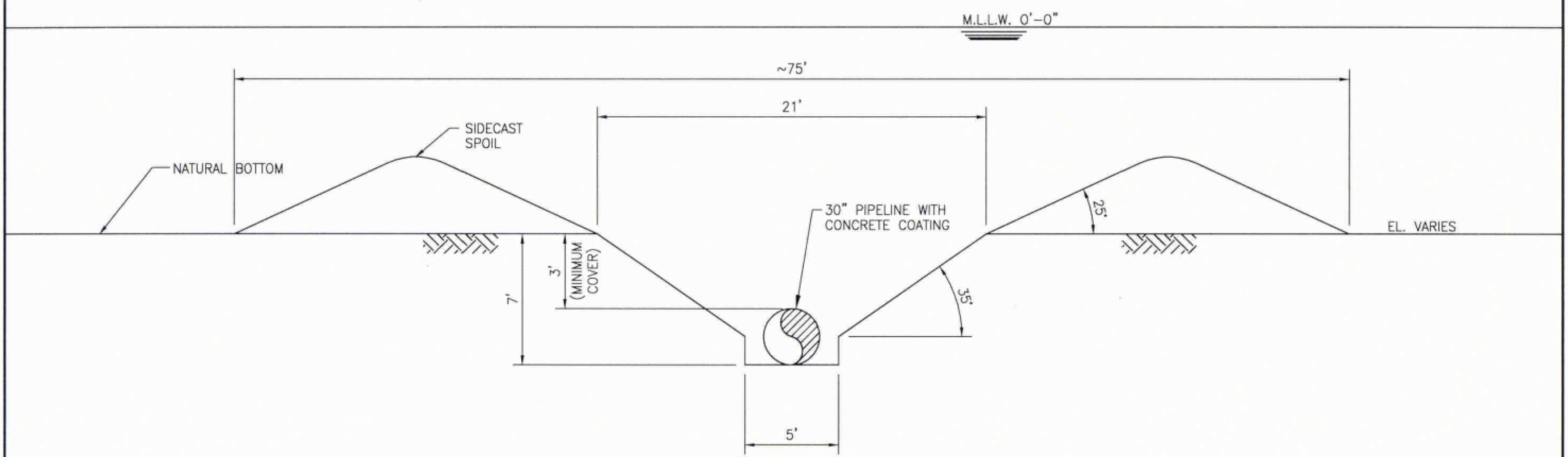
The plow will be stopped approximately 160 feet prior to the crossing of the AT&T and Cross Sound cables. It will then be picked up and carried over the cables and plowing reestablished approximately 160 feet after the cable crossings.

The method of installing the pipeline across the cables is described in Section 1.5.3.6. Supplemental lowering of the pipeline at the cable crossings will be performed by divers and air-lift or similar equipment.

1.5.3.3.3 Spools and Tie-In Locations

The method of installing the pipeline at the IGTS and FSRU tie-in locations is described in Sections 1.5.3.4 and 1.5.3.5. Excavation of materials at the tie-in locations will be performed using submersible pumps and supplemented by divers. The excavation methods, locations and dimensions, spoil handling, backfilling, and measures to minimize potential impacts are discussed in Resource Report 2 (Water Use and Quality) and Resource Report 7 (Soils).





TYPICAL SUBSEA PIPE DITCH BY TOWED PLOW METHOD (3 TO 4 FT. OF COVER)

SCALE: N.T.S.

NOTES:

1. TRENCH CROSS SECTIONAL AREA IS APPROXIMATELY 79 SQUARE FEET.
2. TRENCH VOLUME FOR 19.7 MILES IS APPROXIMATELY 304,500 CUBIC YARDS.

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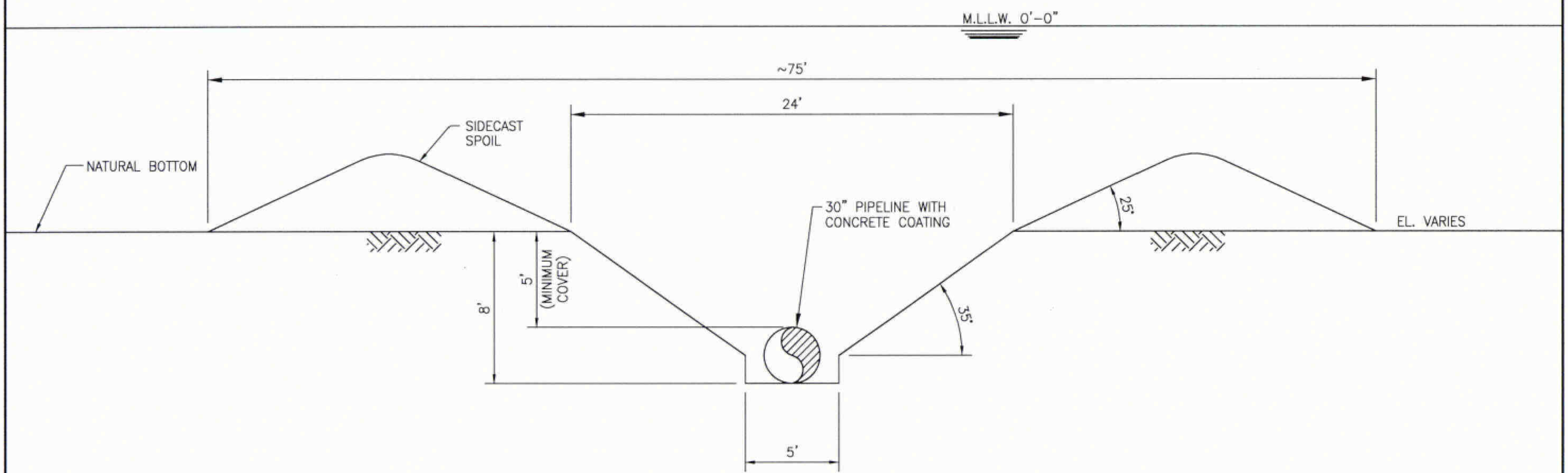

TYPICAL SUBSEA PIPE DITCH
BY TOWED PLOW METHOD
(5 FT. OF COVER)

SCALE: N.T.S.

NOTES:

1. TRENCH CROSS SECTIONAL AREA IS APPROXIMATELY 101 SQUARE FEET.
2. TRENCH VOLUME FOR 2 MILES IS APPROXIMATELY 39,500 CUBIC YARDS.

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1.5.3.3.4 Special Topography

Broadwater's marine surveys completed during 2005 confirmed the presence of hard material in the Stratford Shoal area of Long Island Sound (MP 13 to 14, or just under 5% of the approximately 21.7-mile route); however, the instrumentation was unable to identify whether the material was mineral soil or solid rock. Subsequent direct observation showed the presence of pebbles, cobbles, and small boulders. The contingency plan for construction across Stratford Shoal is provided as Appendix C.

Post-lay plowing in the Stratford Shoal crossing area will necessitate additional pull force and introduce the potential for the excavated boulders to damage the pipeline. A reduced rate of progress to permit closer monitoring of the trenching progress and immediate identification and removal of any boulders that may become lodged between the plowshares and the concrete weight coated pipeline will be utilized.

Contingency plans for a pre-pipelay trenching across Stratford Shoal will be developed and will include detailed discussions with suitable dredging contractors.

1.5.3.3.5 Sediment Resuspension

Lowering of the pipeline will result in the unavoidable resuspension of some sediments, which has the potential to affect water quality through increased turbidity and through reintroduction of buried contaminants to the water column. Based on sampling conducted by Broadwater in spring 2005, contaminant levels encountered during construction of the Project are not expected to be significant.

Broadwater completed a laboratory analysis of sediment samples collected along the extent of the Project and no elevated levels of contamination were identified. Broadwater also modeled the fate and transport of suspended sediments to determine the potential for water quality impacts and the potential impacts on marine organisms from sediment and contaminant deposition.

The modeling results demonstrate that increased sediment in the water column resulting from construction of the Project would have no significant impact to the water column, or to existing ecosystems within Long Island Sound. Detailed sediment transport results are provided in Resource Report 2 (Water Use and Quality).

To verify the modeling results that indicate that turbidity generated during the course of construction will result in only minor, temporary impacts, Broadwater will implement a monitoring program throughout the construction phase to characterize the actual sediment plume generated and to provide a comparison against modeled results. Monitoring will focus on defining the extent of the suspended sediment plume associated with the sediment disturbance. This will be accomplished using a combination of real-time instrumentation and laboratory analysis of water samples as follows:

- Periodic turbidity profiling measurements using in situ optical backscatter (OBS) monitoring equipment;

- Continuous in situ acoustical backscatter monitoring for suspended sediment using an acoustic Doppler current profiler (ADCP);

- Grab sample collection for laboratory analysis of TSS;

- Periodic temperature and salinity profiling measurements using conductivity, temperature, and depth (CTD) equipment; and

- Concurrent time and positional information using a differential global positioning system (DGPS).

The OBS and ADCP backscatter data will be used in conjunction with the grab samples for TSS to achieve wide spatial and temporal coverage of the anticipated suspended sediment plume in near real-time. Vertical profiling of temperature and salinity will provide information on ambient conditions that may be contributing to plume dynamics. All data will include time and positional information from the shipboard DGPS system.

1.5.3.4 Subsea Tie-in with YMS Mooring Tower

The YMS mooring tower structure will support the 30-inch pipeline riser that will tie in the newly laid subsea connecting pipeline with the FSRU. The riser will be pre-installed and hydrostatically tested during fabrication of the YMS.

Installation of the fabricated spools, including the expansion loop, will be performed after all lifts and construction activities are completed for installation of the YMS jacket, the YMS mooring head, and the YMS/FSRU mooring arm yoke. Spool installation will be performed using a DSV as the work platform.

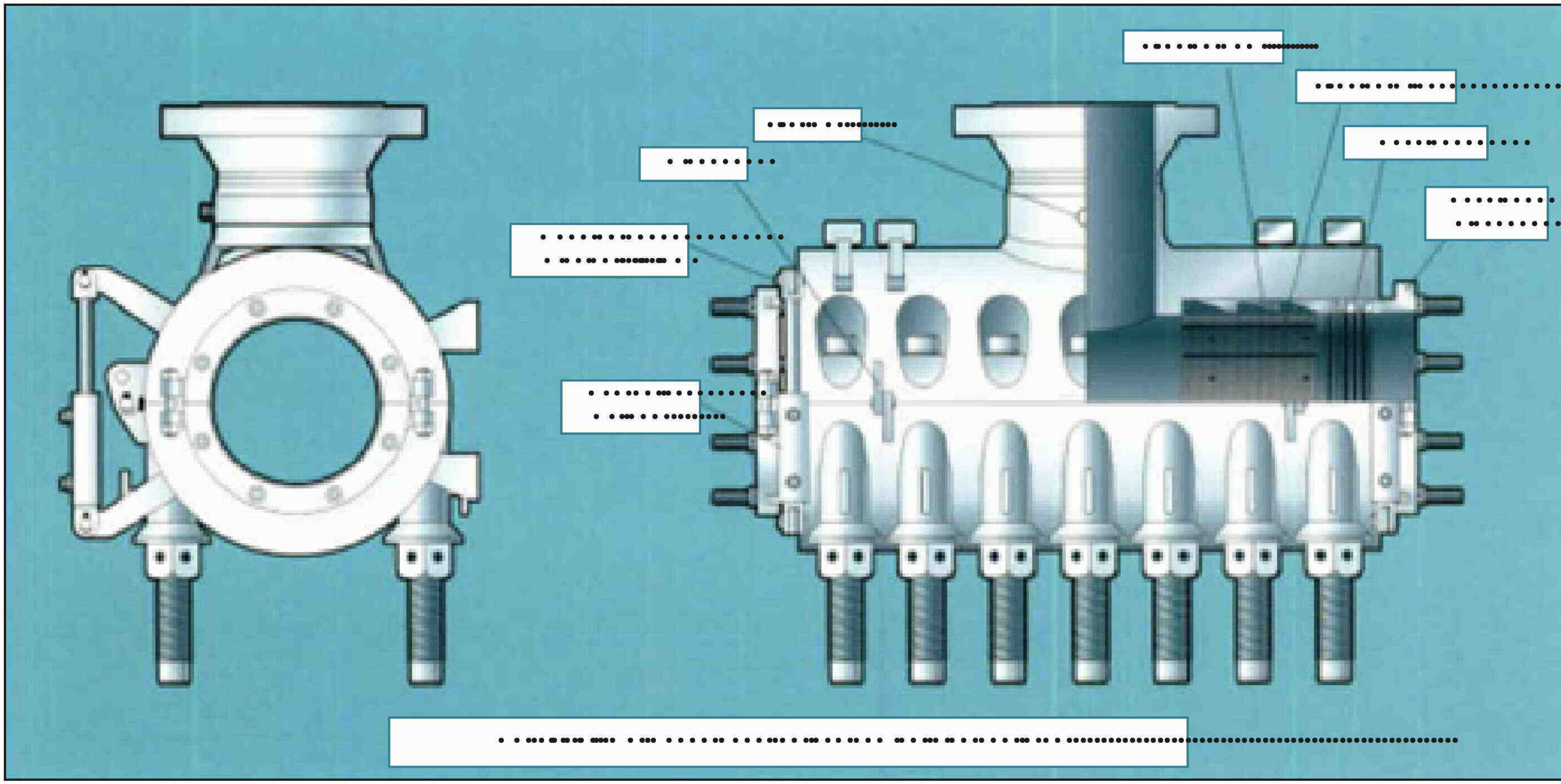
The riser will have an RTJ flange with blind at its base. The RTJ flange will be positioned inside the profile of the structure for protection during transportation and structure installation. The riser will be flooded from the topside and the contractor will implement safety checks to ensure there is no differential pressure in the riser before diver connection operations commence.

1.5.3.5 Subsea Tie-in with IGTS

Hot Tap Connection

The existing IGTS subsea connecting pipeline will be modified to accommodate the subsea connection of the Broadwater subsea pipeline. This will be accomplished by installing a mechanical hot tap connection. The connector will be a split tee mechanical connection which, once installed, will allow for a branch connection through a 24-inch full-opening ball valve (*see* Figure 1-18).

The area including both the hot tap facility and the Hot Tap Connecting Spool will be excavated using submersible pumps and air-lift techniques.



Divers will mark the existing IGTS pipeline with buoys prior to the vessel setting up in the area. Anchoring patterns will be developed, reviewed and approved such that all anchors will be a minimum of 1,000 feet away on the far side and 500 feet away on the nearside from the pipeline. The area will be excavated to a suitable elevation below the natural seabed to allow ready access to the selected section of the IGTS pipeline for the Hot Tap installation and to an elevation that will accommodate the connecting spool and provide sufficient depth to minimize the profile of the spool components relative to the natural seabed (approximately 8 ft [2.44 m] below the sea floor).

After the area is excavated, the section of the IGTS pipeline to be tapped will be stripped of all concrete weight coating using water blasters. Saws and other such devices will not be used.

The hot tap will be lowered and attached to the IGTS pipeline. After all flanges and stud bolts have been tightened, flange spacing measurements will be verified to ensure the appropriate clamp compression has been obtained. The fitting will be leak tested and function tested to insure a proper seal around the pipe. The pipeline will be tapped utilizing a special hot tap tool and then the hot tap machine will be recovered. The pipe coupon, the section of pipe cut out, will be inspected to verify the integrity of the IGTS pipeline.

The design of the hot tap clamp has integrated a number of features to assist in the installation of the device, such as hydraulic opening and closing arms, piloted body studs, and tension-able packing flanges. The diver-assisted process does not require any welding, protecting the integrity of the operating line and overall pipeline system.

Fabricated Spools

The installation of the fabricated spools at the IGTS interconnection will be performed at different stages during construction:

- The Hot Tap Connecting Spool, because of its estimated size and weight, will be installed after completion of the pipe lay operation by the lay barge using its heavy-lift derrick;

- The Pipeline Tie-in spool installation will be performed using a DSV and will coincide with the final stages of the tower installation; and

- The Pig Receiver Spool will be installed by a DSV just prior to hydrotest operations. The pipeline valve upstream of the Hot Tap Connecting Spool will be closed and the Blind flange will be removed. The Receiver and associated piping and tubing will be installed then the pipeline valve will be re-opened. Upon completion of the pigging run, the valve will be closed, the by-pass line and Receiver, complete with the received pig, removed, the Blind reinstalled and the pipeline valve opened.

After the hot tap is securely attached and the lateral pipeline flanged to the assembly, the exposed pipeline and assembly will be covered to ensure proper coverage and protection. A blind flange will be secured to the hot tap protecting the tie-in flange for future spool installation. Divers will install sandbags and/or supports as required to support the added weight of the hot tap.

Later, a set of tie-in spools will be installed connecting the hot tap to the Broadwater pipeline. The attached spool section will be supported and sand bagged. Protective cover will be installed.

The Hot Tap Connecting Spool will contain a flange connection for attaching the Pig Receiver Spool. The flange will normally have a Blind attached that will only be removed when a pigging operation is scheduled. The DSV including dive team will mobilize the Pig Receiver Spool to site, close the pipeline valve upstream of the Blind, remove the Blind, connect the Receiver and the 8-inch flexible by-pass pipe to the 8-inch flange located on the 8-inch x 24-inch tee and reopen the pipeline valve. Upon completion of the pigging run, the valve will be closed, the by-pass line and Receiver, complete with the received pig, removed, the Blind reinstalled and the pipeline valve opened.

The protection of the valves and the hot tap will be required as a temporary measure during construction and/or as a permanent installation for the producing stage. Protection of the components can be provided using mats, sandbags, and/or prefabricated protective structures. However, as a general rule, all components that will require possible access during operation will be installed with a protective structure. This will also be the case, if any part of a component protrudes above the seabed.

1.5.3.6 Cable Crossings

The pipeline route, will cross two foreign utility cables during its installation. The two crossings are detailed below:

- AT&T – Owner: American Telephone and Telegraph Company; and
- Cross Sound Cable (CSC) – Owner: Babcock & Brown Infrastructure Ltd.

The AT&T cable is a fiber optic telecommunications cable which traverses from East Haven to Shoreham, Long Island. The cable is between 4 and 6 inches in diameter and is buried six to seven ft below the natural seabed.

The CSC Cable is a direct current (DC) electrical power transmission cable consisting of a bundle of two solid dielectric cables and a fiber optic telecommunications cable, which traverses between New Haven and Brookhaven, Long Island. Each electric cable is 4.1 inches in diameter and the fiber optic cable is approximately 1 inch diameter. The CSC cable is buried 6 to 7 ft below the natural seabed.

Crossing Preparation

The Code of Federal Regulations 49 CFR Part 192 (Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards) requires a minimum of 12 inches of separation between cable and pipeline. However, an alternative separation may be determined during discussions with the respective cable owners. Broadwater will install a crossing bridge over each of the two foreign utility cables to establish the required separation.

As shown on Figure 1-19, Broadwater will design a crossing bridge with appropriate pipeline transition based on pipeline and sediment characteristics and will develop construction drawings specifying the mat spacing and height required to achieve the agreed upon separation between the bottom of the pipeline and the top of the cable. Separation concrete mattresses will be placed over the existing cable to maintain the minimum agreed upon separation. Design calculations, proposed construction drawings and planned installation schematics will be developed by Broadwater and submitted to the cable owner for review, discussion and approval.

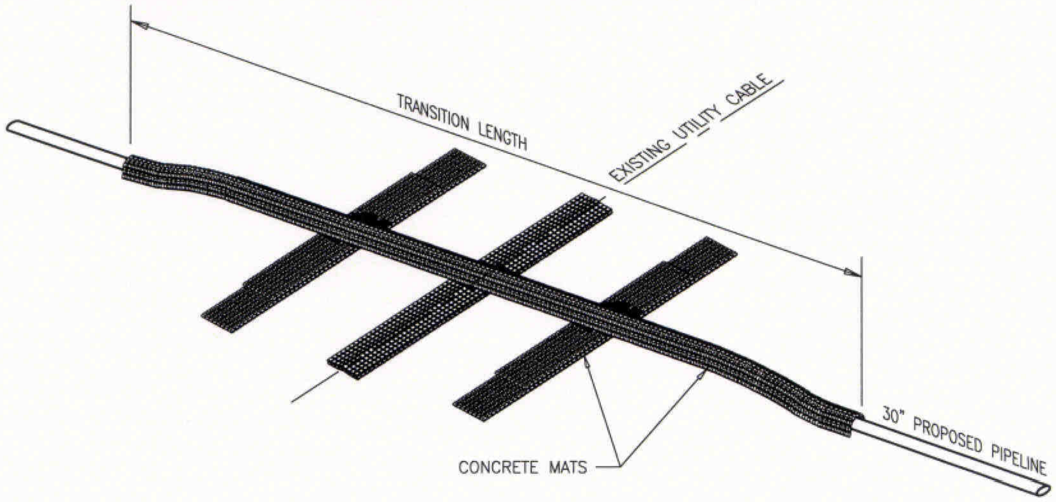
In order to verify safe and proper installation, the contractor will utilize high resolution sonar and diver-assisted investigatory equipment to locate the foreign cable. Prior to any site occupation by the pre-crossing spread and construction, the cable corridor will be physically marked and the as-found cable fixes entered into the barge or vessel's survey system. Broadwater will have cable crossing anchor patterns developed and will submit these to the cable owner for review and approval prior to commencing operations.

The contractor will excavate and then place pre-lay concrete mattresses on either side of the marked cable, creating a crossing bridge, in accordance with Broadwater and the Cable Owner's approved design. The contractor will then install the separation mattresses over the existing cable.

Crossing Completion and Protection

Following completion of the second pipeline lowering pass with the post lay plow, the contractor will complete the cable crossing in accordance with approved installation drawings. Pipelay operations, anchor vessel positioning and touch-down positioning will be monitored utilizing the most suitable surface and acoustic survey positioning and monitoring equipment to ensure that the pipeline is laid across the pre-installed bridge mattresses.

The pipeline will be lowered so that the top-of-pipe is three feet below the natural bottom, however the lowering operation will cease approximately 160 feet from the as-found cable location. The pipeline will gradually breach the seafloor, ramp up the pre-installed concrete mattresses, cross over the foreign cable, and contact another set of concrete mattresses on the opposite side, creating a bridge with a minimum of 12-inches of separation between the bottom of the Broadwater pipeline and the top of the cable. The pipe will then gradually taper back downwards until the three-foot of cover is re-established. Airlifting of the material below the pipeline will be completed by divers and will result in the lowering of the pipeline onto the bridge supports. Portions of the



TYPICAL FOREIGN UTILITY CROSSING

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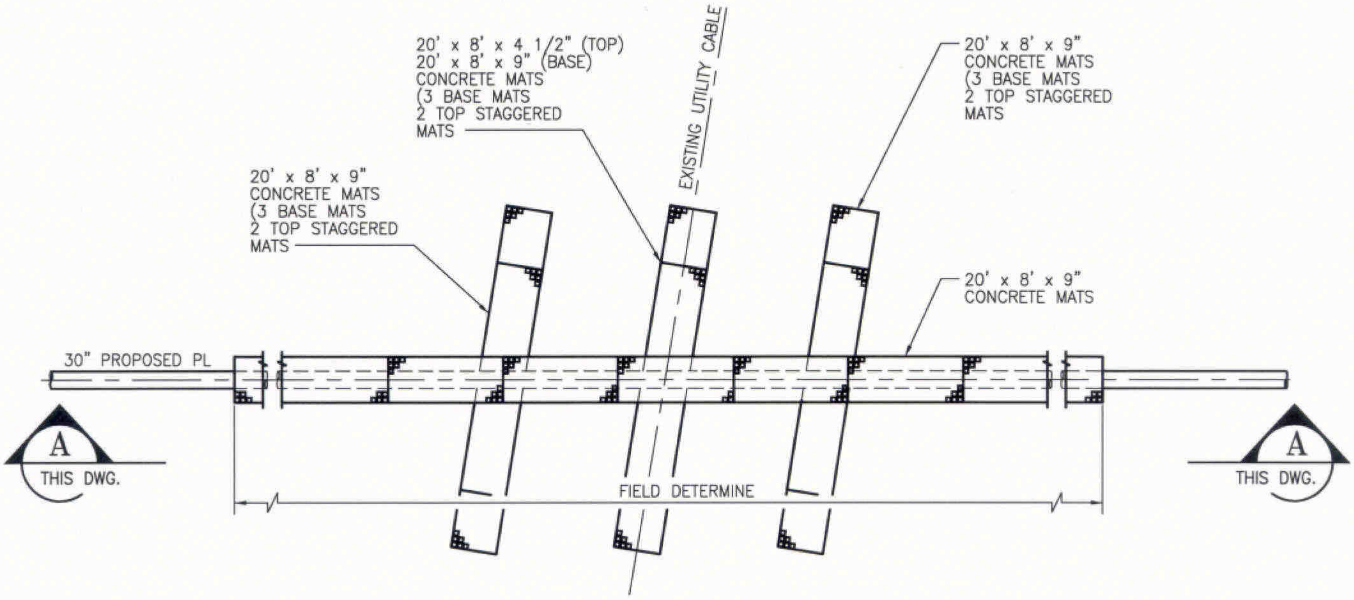

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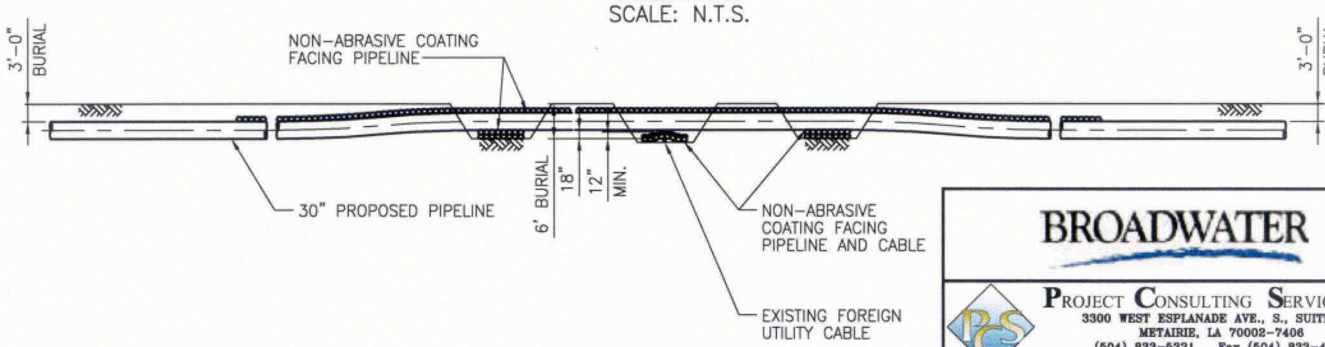

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BROADWATER ENERGY
30" O.D. PIPELINE
TYPICAL FOREIGN UTILITY CROSSING

DRAWN BY: J.E.F.	CHK'D. BY: J.H.R.
DATE: 6-9-05	APPRV. BY: T.O.
DWG. NO. 05032-040	REV B

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pipeline with less than three feet of cover will be covered for protection with rock and/or concrete mattress such that there is a smooth transition back to natural bottom.

1.5.3.7 Backfilling

Backfilling of the trench will be accomplished by the settling of the trench walls and natural sedimentation except as noted below. The time between trenching and completion of natural backfilling of the trench is estimated to be 36 months, as discussed in Resource Report 2 (Water Use and Quality). While a residual depression may still be evident after 36 months, the bottom contours are anticipated to be within approximately 1 foot of preconstruction contours.

The first two miles of pipeline from the FSRU will be mechanically backfilled with clean fill. Material for mechanical backfilling will be imported from an approved location. This material will be comprised of rock that will be dumped from a suitable vessel to ensure accurate placement of backfill in the trench. Installation of the rock will likely be accomplished via drop tubes (or similar) to ensure accurate placement of the fill material and to minimize incidental deposition, and additional impact, of the fill material away from the trench line. As necessary, diver support will be utilized to ensure accurate placement of fill material. The length of time between trenching and mechanical backfilling will be approximately one month.

All areas requiring hand or submersible pump excavation (i.e., tie-ins, spools, cable crossings) will also be protected using mats, sandbags and/or pre-fabricated protective structures. To complete backfilling, and similar to the first two miles of the pipeline route, clean back-fill material will be imported and placed from a suitable vessel to ensure accurate placement of backfill in the trench.

1.5.3.8 Hydrotest and Dewatering

The installed pipeline, the riser on the YMS structure, and fabricated assemblies (spools) will be hydrostatically pressure-tested as required by regulation in accordance with 49 CFR Part 192.

Prior to the commencement of the filling operation, all work required for the installation of the pipeline will be completed, including lowering, span remediation and support installation at the two utility crossings. A barge or vessel will be mobilized that will support the pipeline filling, gauging and cleaning operation at either the FSRU or IGTS end of the installed pipeline.

Prior to initiating hydrostatic testing a cleaning pig propelled with seawater will be run to remove dirt and construction debris from the pipeline. The method used to remove construction debris ahead of cleaning pigs will be to recover solids after the pig has been received at the temporary receiver and the barrel containing the pig and debris will be recovered to the DSV.

Hydrostatic pressure testing will be conducted using filtered seawater. Suction hoses will be lowered into the water approximately 20 to 40 feet below surface to pump water into the pipeline. Filtering of the seawater will be performed during the flooding (pipeline filling) process to ensure that the water in the line is clean. The method used to filter seawater prior to transfer into the pipeline will be to pump the seawater through a U.S. standard sieve 200 mesh screen. The seawater will be treated using an injection pump and a storage/transfer system capable of handling the quantity of chemicals required for biocide injection.

A subsea temporary pig launcher head will be installed at the FSRU end of the pipeline that will be pre-loaded with all required gauging and filling pigs. The launcher will have a means of launching one pig at a time and have an inlet of sufficient size to allow a minimum flow rate of four thousand gallons per minute fill rate. A barge or vessel will be set-up at the IGTS end of the pipeline to attach a temporary pig receiver. The receiver will have a means to capture any debris not removed during the installation process and have a means to capture and dispose of water that will arrive before and after the pigs in a manner consistent with the regulatory requirements. Construction debris ahead of cleaning pigs will be captured for disposal.

To hydrostatically test the pipeline, the temporary launcher located at one end of the pipeline and the temporary receiver located at the other will be replaced with test heads. The high-pressure testing equipment will be connected to the test head to hydrostatically test the pipeline using the following equipment; a Dead Weight Tester, rotating chart, or a strip chart recorder that can be used to the same resolution, a calibrated test thermometer for recording ambient temperature, an accurate large diameter Bourdon tube type gauges (with mirror backing), graduated in pounds per square inch (psi). The range must indicate the specified test pressure near the middle gauge range.

The pipeline will be hydrostatically tested and monitored to confirm there will be no loss of pressure during the minimum 8 hours of test prescribed by code. After acceptance of the hydrostatic test, the pressure will be bled off and both pipeline end valves will be closed. Anticipated volume of water required to fill the approximately 21.7-mile-long pipeline is approximately 3,909,520 gallons. The intake and discharge locations could be located at either end of the pipeline depending on the Contractor's execution strategy.

After the installation of the YMS structure, the pipeline will be connected to the YMS with a three piece spool arrangement. At the IGTS end of the pipeline, the pipeline will be connected to the Hot Tap connector installed on the IGTS pipeline with a two piece spool arrangement. After these tie-ins have been completed, the dewatering (Pre-Commissioning) operation will commence using the permanent YMS pig launcher to launch the dewatering pigs. The dewatering pigs will be bi-directional, high sealing, and high performance polyurethane for maximum efficiency.

At the IGTS tie-in, a DSV with dive equipment and a team of divers will be set-up to operate the tie-in valves and to connect and disconnect the pig receiver. A storage barge may also be required to hold the fill medium during neutralization of the biocide treated water. When the dewatering pig is launched, the treated hydrostatic test water will be discharged from the pipeline and routed into a holding tank onboard the vessel or barge.

In the holding tanks the biocide treated fill medium water will be neutralized using hydrogen peroxide with continuous analysis to ensure that a correct dosage is being injected. The injection operation will be computer controlled and monitored. The dosage rate can range from 150 ppm to 750 ppm depending on the remaining active constituent. The hydrostatic test water will be discharged back to Long Island Sound only after the biocide has been effectively neutralized. After the majority of the test water has been discharged and accounted for, the line will be dried and then purged with a slug of nitrogen. This will be followed by the introduction of dry natural gas.

1.5.3.9 Support Vessels

Support vessels will be mobilized by the pipeline contractor to assist the lay barge or vessel.

Typical Dive Support Vessel

Mooring for a typical DSV will consist of three or four anchors placed at pre-selected locations either by the DSV or with assistance from a support tug. The typical DSV has suitable back deck space to house the relevant diving and construction equipment and usually has minor fabrication facilities. The vessel will have accommodation for the marine and construction crews to work 24/7 in 8 or 12 hour shifts with associated catering and support facilities. DSVs are usually utilized for shallow to mid water work where short-duration diving operations and subsea construction is required.

Dynamically Positioned Dive Support Vessel

A DPDSV has redundant DP systems to ensure diver safety. No anchoring is required and the vessels are usually larger and more versatile than a moored DSV. The typical DPDSV will have saturation diving capability and will accommodate much larger marine, diving and construction crews. The vessel will be utilized in congested areas where anchoring is a concern, where the seabed is less than favorable for anchoring or where the work program necessitates that surface diving is uneconomical. A DPDSV will have accommodation and support facilities to house a large crew working 24/7 in 12 hour shifts. The DPDSV will effectively operate in water depths greater than 40 ft.

Anchor Handling Tugs

AHTs are different from normal tow tugs. They are designed and purpose built with more powerful engines, larger winches, and smaller back decks and lower centers of gravity for maneuverability. Pipe lay operations and pipeline lowering will proceed on a 24/7 basis. It is likely that the contracted lay barge will bring its own AHTs with experienced operators and crews to the Project for efficiency and safety reasons.

Survey Vessel

The survey vessel is anticipated to be in the 125-foot class or smaller. Survey vessels of this type are typically equipped with the following basic survey instruments: DGPS positioning, echo sounder, sidescan sonar, magnetometer, and pipeline and cable locator.

Pipe Supply Barge and Pipe Hauler Tug

Pipe supply barges are usually flat-top barges that range from 100 to 300 feet in length. They typically have no propulsion, but are hauled by conventional tugs that are available in the local area. Line pipe and other materials are loaded onto the barges at a suitable port location, hauled offshore to the lay barge, and offloaded by the lay barge's crane.

Hydrotest and Dewatering Support Vessels

Hydrotest support vessels are usually platform supply vessels with cranes and deck space capable of holding large amounts of equipment such as flooding pumps, air compressors to run the pigs, hose reels, pressurizing pumps, instrumentation and chemical injection pumps. Dewatering support vessels are usually platform supply vessels capable of holding large amounts of equipment such as compressors and dryers. Both the Hydrotest and Dewatering support vessels could hold their position using either anchors or DP.

Fall Pipe Vessel

A fall pipe vessel is usually a barge and/or vessel that is used for controlled placement of rock over the pipeline on the seabed.

Security and Escort Boats

The security and escort boats would likely be a vessel in the class of a harbor pilot boat or a lobster fishing boat. It accompanies the lay barge, if necessary, to keep other vessels fully aware of the lay barge's movements. Should any vessel (such as a pleasure yacht) inadvertently enter into the construction area the security and escort boats may sail out to the craft and ensure safe passage of the vessel out of the area.

Personnel Carriers and Utility Launches

These are common utility vessels of small class capable of transporting personnel and light materials to and from shore. These are typically chartered from local areas.

1.5.3.10 Timing and Duration of Pipeline Construction

FSRU hook up and commissioning is planned to commence December 01, 2010 with first gas by December 31, 2010. To accommodate this completion schedule the anticipated pipeline construction schedule and work sequence is as follows:

- September/October 2009: Pre-lay survey and/or diving operations will confirm seabed conditions – for example, to confirm that there are no new wrecks in the construction corridor. Note that a protocol for unanticipated discovery of cultural resources will be in effect for construction as described in Resource Report 4 (Cultural Resources – Privileged Information version).

- Main Pipe Lay - October 2009 through April 2010:
  - A DSV installs the IGTS subsea hot tap, cable protection and cable bridge supports;
  - The lay barge completes laying the pipeline onto the seabed and across the cable bridges, followed by pipeline lowering. The lay barge also installs

the IGTS hot tap connecting spool, and the downstream FSRU tie-in spool which makes up one half of the expansion loop;
- A DSV installs the check and isolation valve spool at MP 0.4;
- The first 2 miles of the lowered pipeline are mechanically backfilled while a DSV completes cover and protection installation at the two cable crossings; then
- Hydrotest vessels complete cleaning pig runs, then fill the pipeline with sea water and complete hydrostatic testing.

- Q4 2010: The FSRU/YMS contractor will set the pre-fabricated Mooring Tower jacket on the seabed at the FSRU site, and then install the four deep piles to secure the mooring tower (*see* Section 1.5.2.2).

- Remaining Tie-ins - November/December 2010:
  - A DSV installs the remaining pre-tested tie-in spools at the IGTS and FSRU sites, followed by mechanical backfilling of the tie-in areas;
  - Hydrotest vessels de-water and dry the pipeline; then
  - Following receipt of the initial cargo of LNG, and supported by hydrotest vessels, the subsea connecting pipeline is purged of air with nitrogen and is then loaded with natural gas.

1.5.3.11 Workforce

Broadwater anticipates that the peak work force to construct the pipeline will be approximately 350 workers on the marine lay barge spread (including support vessels), about 20 to 30 inspection and management personnel overseeing the offshore operations, plus approximately 20 workers supporting operations onshore. The duration of the peak workforce is estimated to be 95 days, i.e., during the period that the lay barge is on site and will comprise the main pipe lay and pipeline lowering (plowing) operations, plus the installation of the initial spool pieces at the IGTS and FSRU tie-ins.

1.5.4 Temporary Onshore Land Requirements

To support construction activities, Broadwater will need to temporarily utilize onshore facilities to facilitate storage and transfer of materials to the construction site. The concrete weight coating will be applied to the pipe at an existing off-site concrete coating plant at a location to be determined during the detailed design stage. Companies capable of applying concrete weight coating for this Project from existing coating plant facilities include Bayou Companies, with locations in Louisiana, and Bredero Shaw, with locations throughout North America. The concrete weight coated line pipe will then be transported to a stockpile and transhipment site where it will be stored awaiting commencement of construction. A space of approximately 10 acres will be required to store the approximately 3,000 forty-foot nominal length joints of concrete weight coated line pipe for the Project.

Because the concrete weight coating will be applied at an existing facility, no environmental impacts associated with construction and/or use of temporary facilities are anticipated.

Following completion of concrete coating, the pipe will be transported via rail to an existing port lay-down area with adequate land-to-sea transfer capabilities, likely in the Port of New York/New Jersey. The actual location of the lay-down area will be determined by the contractor selected to install the pipeline. The use of an existing facility eliminates potential environmental impacts associated with establishing a new site for temporary storage of the pipe. From the temporary storage yard, the pipe will be loaded onto barges, transported to the Project area, and directly offloaded to the lay barge to minimize handling. No pipe storage yards will be needed on Long Island Sound. Upon selection of the temporary pipeyard, Broadwater will notify FERC and obtain appropriate clearances as needed.

During the course of construction, the contractor will need temporary space on the shore of Long Island Sound, primarily for shuttling crews and supplies to the Project site, since the majority of the construction operations will be conducted 24 hours a day, 7 days a week. The only waterfront facility required to support construction activities will be a dock. Based on the amount of existing dockage available in Port Jefferson and Greenport, Broadwater believes that existing facilities are adequate and that no new waterfront facilities will be needed. The contractor will most likely require the use of an onshore office and possibly warehouse facilities to support offshore activities during construction. The selected contractor will identify these locations prior to construction. Given the amount of marine usage throughout the Sound, Broadwater does not anticipate the need to construct new facilities to support temporary construction needs.

1.6 OPERATION AND MAINTENANCE

1.6.1 FSRU

Depending on the size of LNG carrier utilized, it is currently anticipated that two to three vessels will be unloaded each week. The FSRU is designed to accommodate LNG carriers in the size range of 125,000 m^3 up to a potential future vessel size of 250,000 m^3 capacity, but at this time the actual vessel sizes expected to call on the Broadwater facility have not been determined.

As part of the approval process for the Project to commence operations, a Letter of Recommendation from the USCG is required. Conditions arising from the Letter of Recommendation will be incorporated within a Vessel Management and Emergency Plan (Operating Plan). The USCG plan will contain specific requirements for the LNG carrier, pre-arrival notifications, scheduling, Long Island Sound transits, escorts, marine operations, cargo transfer operations, USCG inspection and monitoring activities and emergency operations. There may be other requirements for the transit and LNG discharge that may be different from other vessels operating in Long Island Sound. These conditions are still to be determined, but Broadwater anticipates at a minimum the following marine procedures.

- All LNG carriers destined for the terminal will be in possession of valid certification as required for International trade, including a USCG Certificate of Compliance for all non-USA flagged vessels.

- All LNG carriers destined for the terminal will be thoroughly reviewed by Shell following inspection under the Oil Companies International Marine Forum (OCIMF), Ship Inspection Report program.

- An LNG carrier on passage to the Broadwater Terminal will notify the Terminal, the USCG, the Immigration and Naturalization Service (INS), pilots, tug operators and shipping agents at least 96 hours before arrival. Advance notice will include validation that all onboard safety related systems and equipment are operational.

- The LNG carriers will remain at sea prior to an agreed arrival time at a location designated for a USCG Security boarding, if required, or at the pilot station. LNG carriers will not anchor in Block Island Sound to await pilots or other formalities.

- USCG inspectors may conduct a pre-arrival security inspection of the LNG carrier and crew before entering US territorial waters or before entering Long Island Sound.

- A state licensed pilot will board each LNG carrier for the transit through Block Island Sound and Long Island Sound. The same pilot will complete the docking and undocking operations at the FSRU and remain onboard throughout the discharge operation. The Broadwater terminal will confirm readiness to receive the LNG carrier prior to the pilot boarding.

- Coordinated scheduling of LNG carrier transits will take into consideration other marine users and avoidance of peak congestion at the Race.

- Broadwater will ensure that an adequate number of suitable tugboats are available for each LNG carrier operation. It is anticipated that each tug (up to four tugs in total) will be purpose-built to support Broadwater's operations and will have a bollard pull capacity of 60 metric tonnes. The tugs will likely be constructed at an existing shipbuilding facility within the U.S. with the capacity, ability, and proven track record for this type of construction without modification to its existing facilities. Table 1-4 includes a partial list of existing shipbuilding facilities within the U.S. at which the tugs could be constructed.

The tugs will be equipped with water fire-fighting equipment classed ABS Firefighting 1, and they will have an escort notation. Tug utilization (subject to USCG review and approval) is expected to be as follows:

- Two tugs may be used to escort LNG carriers through the Race and during the transit of Long Island Sound;
- Three or four tugs (depending on vessel size) will be required to assist the LNG carrier when berthing alongside the FSRU;
- Two tugs will remain on standby in the vicinity of the FSRU whenever an LNG carrier is berthed. The duties of the standby tug will be to prevent other vessels from approaching the moored LNG carrier and to assist the vessel in the event of an emergency departure.
- Two or three tugs (depending on vessel size) will be required to assist with unberthing operations.

Table 1-4 Existing Eastern Shipbuilding Facilities with Capacity to Construct Suitable Tugs

	Builders			
Shipyard	**Large**	**Small**	**City**	**State**
Kelley Shipyard, D.N.		X		
American Shipyard		X	Newport	RI
Blount-Barker Shipyard		X	Warren	RI
Bath Iron Works	X		Bath	ME
Washburn & Doughty		X	East Boothbay	ME
Electric Boat	X		Groton	CT
Kvaerner Philadelphia	X		Philadelphia	PA
Chesapeake Sbldg.		X	Salisbury	MD
Newport News Shipbuilding	X		Newport News	VA
Intermarine USA		X	Savannah	GA
Sun State Marine		X	Green Cove Springs	FL
Keith Marine		X	Palatka	FL
North Florida Shipyards		X	Jacksonville	FL
Atlantic Marine		X	Jacksonville	FL

Tugboat support considerations are also described in Resource Report 11, Safety and Reliability, Section 11.4.2.

- After berthing, an INS Officer will board the vessel to complete arrival formalities, including the verification of the crew against the previously supplied crew list.

- Following confirmation by the INS Officer to proceed, USCG personnel will complete safety inspections of both the FSRU and LNG carrier. A pre-discharge meeting will be held between the terminal and carrier staff to confirm discharge procedures and review of the safety checklist. Concurrent with these activities, a hard wired communications system will be established and tested between the carrier and the FSRU.

- On confirmation of the discharge procedures being agreed, the loading arms and Emergency Shutdown System (ESDS) will be connected. The ESDS allows either the terminal or LNG carrier to automatically or manually stop the unloading process whenever an abnormal condition occurs.

- After a successful test of the ESDS, LNG transfer may proceed according to the agreed procedures with the approval of the USCG.

- At the completion of cargo unloading operations, the loading arms must be drained and purged before disconnection, in accordance with standard LNG practice. The arms are drained by gravity either directly to the LNG carrier cargo tanks via the carrier's cargo lines or to the FSRU drain tank and thereafter pumped to the FSRU storage tanks.

The duration of activities associated with an LNG carrier unloading operation is shown in Table 1-5 below.

1.6.2 FSRU and Yoke Mooring System Maintenance

The FSRU and YMS are designed for high reliability and low maintenance. Maintenance plans will be developed at the detailed design stage. The maintenance regime will include frequent visual inspection (for the YMS this will be via permanently fitted access ladders); operational checks and tests; routine onboard mechanical and electrical maintenance; lubrication schedules and regular steelwork examination; and survey both above and below the waterline.

Both for the FSRU and YMS, underwater inspection may require some underwater surface cleaning of the hull and other parts. This will be performed generally to remove localized slime and weed growth originating from the Sound and will be completed using a light brushing system carried out by divers. It is expected that this will be undertaken no more than once per year. No recoating of the underwater portions of the facility will take place. Any mechanical repairs to the underwater parts of the FSRU or YMS will be segregated from the seawater by an underwater cofferdam applied by divers such that there will be no environmental impact.

Table 1-5 Proposed Marine Operations
(Proposed operations - subject to USCG review and approval)

Activity	Duration	Comment
LNG Carrier Arrival		
• Check weather limits (approach, berth, unload, unberth), proceed if OK for all operations.		Before Pilot boarding terminal confirms readiness to receive LNG carrier.
• USCG Security Inspection before pilot boarding.		
• Pilot boarding at Block Island Pilot Station.		
• Transit from Pilot Station to terminal (approximately 50 nautical miles).		Compulsory pilotage with 1 or 2 tug escort from the Race to the FSRU.
	5.0 hrs	
LNG Carrier Berthing		
• Final approach to berth and tug hook-up	1.5 hrs	Before final approach, FSRU Person In Charge and LNG carrier Master confirm safety procedures; 3-4 docking tugs made fast during final approach.
• Mooring operations	1.5 hrs	
• Mooring operations completed		Pilot remains onboard; tugs in close standby mode,
LNG Carrier Unloading		
• Connect unloading arms, purge system, and conduct safety checks.	2.0 hrs	Loading Master boards the LNG carrier.
• Loading arm and ship cool down	1.0 hrs	
• Cargo transfer operations	15.0 hrs	Transfer time based on 145,000 m^3 LNG carrier –
• Drain, purge, & disconnect loading arms	1.5 hrs	
LNG Carrier Departure		
• Preparations for departure	1.5 hrs	
• Unmooring operations	0.5 hrs	
• Departure	0.5 hrs	LNG carrier clear of FSRU; tugs dismissed.
• Broadwater to pilot station	5.0 hrs	Pilot departs at Block Island Pilot Station.
Total Time Requirement (entry to exit of LIS)	***35 hrs***	

For onboard maintenance other than the routine onboard mechanical and electrical maintenance set forth above, coating repairs will be ongoing. Proprietary epoxy and polyurethane paints will be used, and they will be applied mechanically, not sprayed. These and other solvents/cleaners will be similar to household-type products in their toxicity characteristics. Surface preparation will also include localized rinsing with freshwater to remove seawater spray salts carried by the wind from the Sound. All debris will be containerized and retained for disposal at a suitable facility.

1.6.3 FSRU Discharges

Operation of the FSRU will result in up to seven point-source discharges into the Sound, including:

- Two ballast water discharge points (port and starboard) located approximately 3 feet (1 m) below the waterline;
- One wastewater discharge point (either port or starboard) located approximately 3 feet (1 m) below the waterline;
- One desalinization overboard (starboard) located approximately 13 feet (4 m) below the waterline;
- One seawater cooling discharge (port) located approximately 13 feet (4 m) below the waterline;
- One inert gas scrubber cooling pump overboard (starboard) located approximately 3 to 6 feet (1 to 2 m) below the waterline; and
- One emergency bilge overboard (port) located approximately 3 to 6 feet (1 to 2 m) below the waterline.

If wastewater cannot be effectively treated to comply with New York State discharge requirements, then Broadwater will route black and gray water to holding tanks, which will be shipped to shore for disposal at an approved treatment facility. The emergency bilge overboard is not discussed in detail as Broadwater does not anticipate any discharge through this overboard for the lifespan of the Project.

FSRU operations also will include three non-point-source discharges into the Sound, including:

- One side-shell water curtain to discharge treated seawater between the FSRU and any moored LNG carrier as a hull integrity measure during offloading operations;
- Uncontaminated deck runoff from storm events; and
- Fire-water bypass system water.

All discharges are expected to meet NYSDEC discharge requirements for contaminant levels and other physical water quality parameters.

Most discharges from the FSRU will have a low residual (0.01 to 0.05 ppm) sodium hypochlorite concentration. Sodium hypochlorite is used to prevent marine growth in FSRU systems. Sodium hypochlorite concentrations will be monitored through sampling of overboard water collected from internal FSRU systems before it is discharged into the Sound. The chlorine concentrations of samples will be determined through a colorimetric assay. As necessary, the production and injection rate of the sodium hypochlorite added to the system at the sea chest will be adjusted accordingly.

Ballast Water System

No contaminants will be introduced into the FSRU's ballast water system prior to ballast water being discharged into the Sound.

Treated Wastewater from the Onboard Treatment Plant

The FSRU will be equipped with a membrane bioreactor (MBR) with the capability of treating both black water and gray water discharges. Based on the typical specifications for an MBR, it is anticipated that the discharge will be compliant with NYSDEC discharge standards. However, if, based upon review and consideration by NYSDEC during the SPDES evaluation process, it is determined that the discharges will not be compliant with applicable regulations, all black water and gray water generated by systems on the FSRU (e.g., sinks, shower drains, and floor drains) that may contain increased levels of detergents and nutrients will be routed to a holding tank and shipped to shore for disposal at an approved facility.

Discharge from the MBR will be tested weekly using an assay for the Most Probable Number (MPN) of viruses. The sample for this assay will be collected from the internal FSRU treatment system and sent off site for analysis. In addition, water quality monitoring plans will be prepared and implemented to ensure adherence to discharge standards in accordance with NYSDEC requirements as determined during the SPDES permitting process (*see* correspondence with NYSDEC presented in Appendix G in Resource Report No. 2 – Water Quality).

Desalination Unit Discharge

The desalination unit discharge will be used to discharge water generated by the desalination unit, which will be used to make potable water onboard the FSRU. The approximate volume of this discharge is 0.6 million gallons per day (2,355 m^3/d). The discharge will be comprised of seawater that had been taken in by sea chest and will have a slight salinity increase of approximately 2%. This equates to a salinity increase of less than 0.5 ppt, which is not significant and not likely measurable since salinity values in the Sound range from 24 to 25 ppt. Based on these values, no impacts on water quality will occur.

Central Cooling Water (Non-routine Operations Only)

The central cooling water overboard will be used only if the FSRU's glycol/water system fails. The actual capacity of the cooling water system, and the associated discharges, will be determined during the final design stage of the Project. While this system will have a permitted discharge point, no discharge will occur under routine operating conditions. The seawater used for cooling will not come into direct contact with machinery onboard the FSRU. Therefore, no impacts on water quality will occur.

Inert Gas (IG) Scrubber Overboard

The IG scrubber is used only infrequently when a cargo tank needs to be purged for cleaning and/or inspection. The IG scrubber will be used approximately once every 5 years. Water from the sea chest will be used to "clean" and cool the inert gas stream used to purge the tanks. Water usage is estimated to be approximately 290,000 gallons/hr (1,100 m^3/hr), with a total of approximately 11.6 million gallons (44,000 m^3) required for a single purge of the entire FSRU.

Side-Shell Water Curtain

To maintain hull integrity of the FSRU and LNG carrier, a constant curtain of water will be directed overboard during LNG transfer from the carrier to the FSRU. Both the FSRU and the LNG carrier will generate side-shell water curtains.

This water will be supplied by the two sea chest intakes and thus will contain residual chlorine levels. The side-shell water curtain will discharge directly into the Sound between the FSRU and the LNG carrier. It is anticipated that water from the side-shell water curtain will be discharged at an approximate rate of 8,718 gallons/hr (33 m^3/hour) from both the FSRU and LNG carrier.

Drainage Systems and Deck Runoff

The fire-water bypass system will not be treated with sodium hypochlorite. Seawater for this system will be utilized only in the event of a fire onboard the FSRU (or testing of the fire-water system) and will be supplied by seawater intakes that are independent of the main seawater intake system. Discharge during any testing of the fire-water bypass system will be overboard via scupper drains, which will return the seawater directly back to the Sound. The volume of water to be used for testing is estimated to be 0.74 million gallons (2,800 m^3), and the testing will occur only once a month during system testing. Runoff from the testing of the fire-water system will not impact the temperature, salinity, or dissolved oxygen content of water in the Sound.

Uncontaminated storm water runoff from the FSRU will be comprised of rainwater and will be directed overboard via scupper drains. The volume of this runoff will be based on local levels of precipitation and will be at ambient temperature when drained to the Sound. Runoff from any on-deck location that has the potential for oil and grease contamination will be collected and routed to the bilge holding tank for shipment to shore.

Spill Potential

The potential exists for spills of various materials from the FSRU, which could enter Long Island Sound and impact water quality. Materials stored on the FSRU with spill potential include aqueous ammonia, ethylene glycol, diesel fuel, and mercaptan, which is used as a natural gas odorant. The diesel fuel will be stored in tanks intergrated into the hull of the FSRU, and the ethylene glycol is restricted to a closed-loop system, minimizing spill potential. The aqueous ammonia and mercaptan will be transported and stored in isotanks with adequate containment to minimize impacts.

These substances are discussed in more detail in Resource Report 11 (Safety and Reliability), Section 11.3.2.3. Per SPCC regulations (40 CFR Part 112) and the proposed revisions to the SPCC Rule (December 2005), facilities that become operational after August 18, 2006, must prepare and implement a plan before beginning operations. Broadwater recognizes this requirement and, preceding FSRU and pipeline operations in 2010, will prepare and submit an SPCC Plan in order to address the potential for spills of substances stored and utilized on the FSRU. The SPCC Plan will describe preventative and response measures that will be implemented in the event of a spill.

1.6.4 Subsea Connecting Pipeline

Operation of the subsea connecting pipeline will vary according to natural gas market requirements. Flow conditions on the FSRU and at onshore locations on the IGTS pipeline will be monitored using Supervisory Control and Data Acquisition (SCADA) systems by the Broadwater FSRU Command and Control facility and the IGTS Gas Control Center, respectively. Both facilities will be manned 24 hours per day. Operation and maintenance records will be maintained per the requirements of 49 CFR Part 192.

Regular pipeline maintenance will include maintenance and pigging at interval lengths specified by the U.S. Department of Transportation (USDOT), the applicant's standard operating procedures, NYSDEC regulations for pipelines, or as conditions warrant. Resource Report 11 (Reliability and Safety) provides a description of regular pipeline maintenance and emergency procedures for the pipeline.

Pigging Operations

Pigging during operations will be infrequent and will have the following general sequence of activities that will span approximately 10 to 14 days depending on weather and type of inspection required:

- With the support of a DSV and diving crew, in order to access the IGTS tie-in any protective devices will be removed and set aside on the bottom, and then backfill will be removed and set aside or recovered to a barge on the surface;
- A temporary pig receiver will be mobilized with the support of the DSV and diving crew and lowered down to the IGTS tie-in spool, flanged in position to receive a pig;

- The permanent pig launcher facilities are located on the deck of the YMS mooring tower. A launcher barrel will be pre-loaded with a pig onshore and flanged into position on the deck of the YMS mooring tower, or the pig will be transported offshore where it will be loaded into the pre-installed launcher barrel;

- The pig will be propelled with the send-out gas stream from the FSRU. Pig speeds will be controlled at the launcher barrel and by adjusting send-out gas flow rates;

- When the pig has been received at the IGTS interconnect, valves located at the receiver will be closed and the receiver barrel containing the pig will be recovered to the DSV. A pollution dome will also be utilized during recovery operations and will be brought to the surface for draining at an approved location (a description of the pollution dome is provided below);
  - Following completion of the pigging operation the blind at the receiver will be reinstalled, protective coverings will be re-established and backfill will be replaced similar to backfill procedures during the original construction, potentially supported by other vessels or barges; then
  - The DSV and any support craft will demobilize.

A pollution dome is an "umbrella" type mechanism that is placed above the area of an opening or disconnection during a subsea operation that may contain trapped hydrocarbons. The pollution dome can be tethered to the subsea equipment and/or suspended using floats or weights. The hydrocarbons will be captured in the pollution dome when the hydrocarbons bubble up in the water. The hydrocarbons are brought up to the surface via a hose connected to the top of the dome, and the hydrocarbons are then captured in a tank onboard the DSV.

In the case of the pig recovery operation, the pollution dome will be located just above a 2-inch vent valve once the pigging operation has been completed and the pig has been captured in the temporary pig receiver. Once the subsea tie-in assembly ball valve has been closed and the downstream valve of flexible hose connection is closed, the hydrocarbons trapped in the closed piping and flexible hose section will be vented to the topside through a hose or through the pollution dome assembly and contained on the DSV. The pollution dome assembly will then be relocated to a position above the temporary pig receiver connection to the subsea tie-in assembly to capture any hydrocarbons from the disconnection of the temporary pig receiver and the connections for the flexible hose.

1.6.5 Permanent Onshore Facilities

Although installation of the FSRU and connecting pipeline is not scheduled to begin until 2009, Broadwater has identified two locations on Long Island—Greenport and Port Jefferson—that can provide the facilities needed to support operation of the Project. Either one or both facilities would be used to support Broadwater operations. The location of each of the considered Long Island facilities is indicated on Figures 1-20 and

1-21. Greenport is located on the north fork of Long Island, and Port Jefferson is located southwest of the Project area on the north shore of Long Island. Permanent onshore facilities will include office space, warehousing, and a waterfront facility. Broadwater anticipates leasing existing facilities for these uses, and no land acquisition is proposed. These facilities will be located within existing marine facilities that are operated by others.

The office and warehousing facilities do not require waterfront access and thus will likely be established in existing facilities in general proximity to the waterfront facilities, but not necessarily co-located with the waterfront facilities. The office space will need to accommodate approximately six to ten people, with conference and training facilities available on site. The office will also function as the emergency response and communications center for the Project. Warehousing will be needed for spare parts, specialist tools, and equipment storage and handling. Broadwater expects that the location of these will be finalized following the selection of a specific waterfront facility. Onshore facilities are discussed in more detail in the Onshore Facilities Resource Reports submitted with the application.

1.7 FUTURE PLANS AND DECOMMISSIONING, REMOVAL, AND ABANDONMENT

1.7.1 FSRU

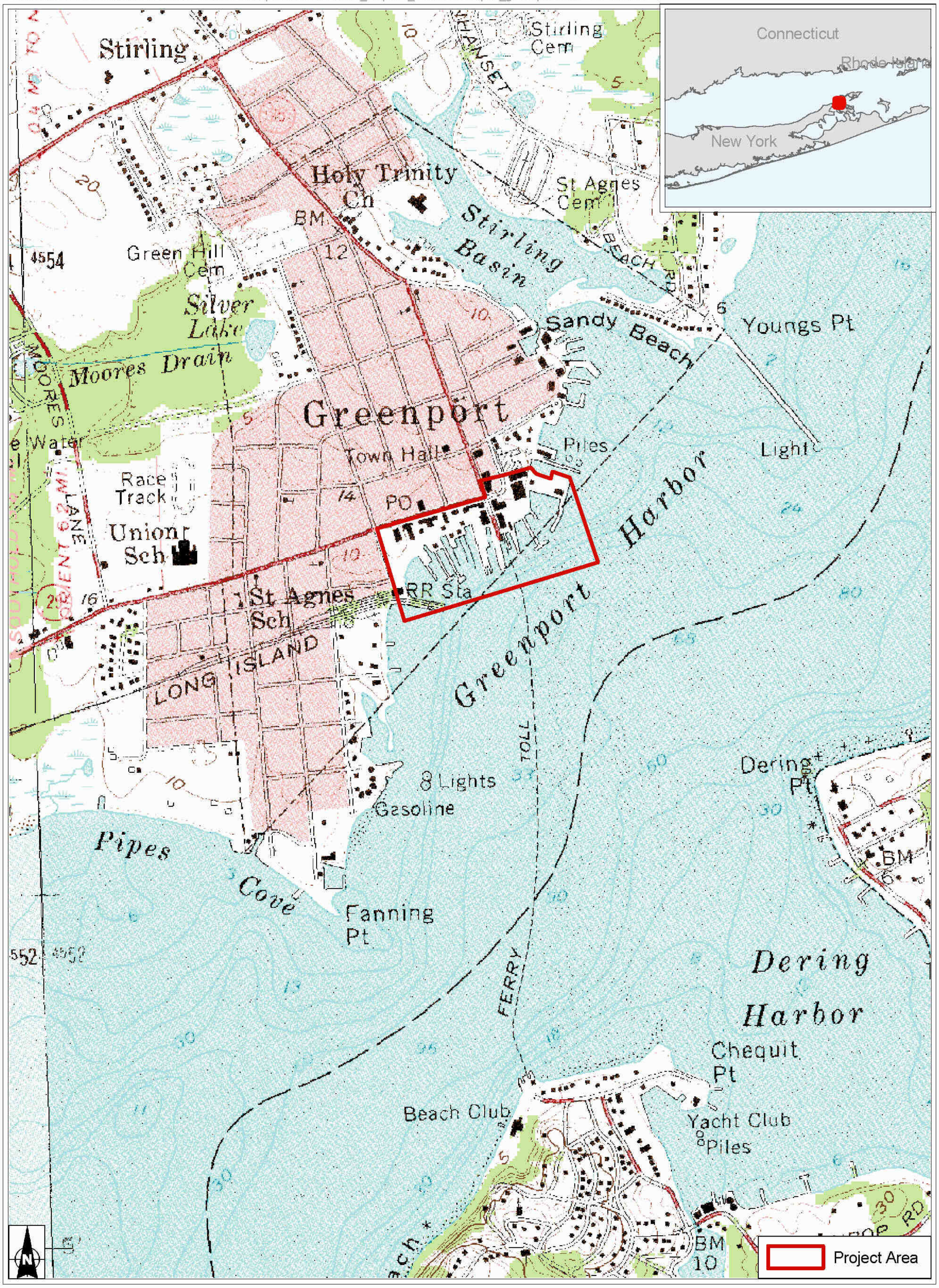
The process of removing the FSRU from its site is straightforward: Upon decommissioning, the FSRU will be removed (decoupled) from the YMS and towed to a shipyard to be overhauled for reuse or recycled, as appropriate.

1.7.2 Subsea Connecting Pipeline

The subsea connecting pipeline that will connect the FSRU facility to the IGTS system will be evaluated at the time of decommissioning to determine whether removal or abandonment would provide the most benefit to the environment. Any NYSOGS lease for the facility may also provide specific requirements for decommissioning the Project. Subsea connecting pipeline decommissioning will begin with pigging the line to remove any debris, scale, or other materials. If the pipeline is abandoned in-place, it would be purged with inert gas and sealed before being abandoned in-place. If the pipeline were to be removed, it would be cut, raised to a salvage barge, and brought to the shore for recycling. The mooring tower would be removed from the seafloor or, alternatively, it could be left in place and converted to an aid to navigation.

1.8 PERMITS AND APPROVALS

The federal and state entities and the environmental permits, consultations, and clearances that may be required for approval to construct and operate the Project are identified below in Tables 1-6 and 1-7.



Source: USGS Greenport, 1956; Southold, 1956.

0 0.1 0.2 0.4
Miles

Figure 1-20 Proposed Onshore Facility Location
Greenport, New York

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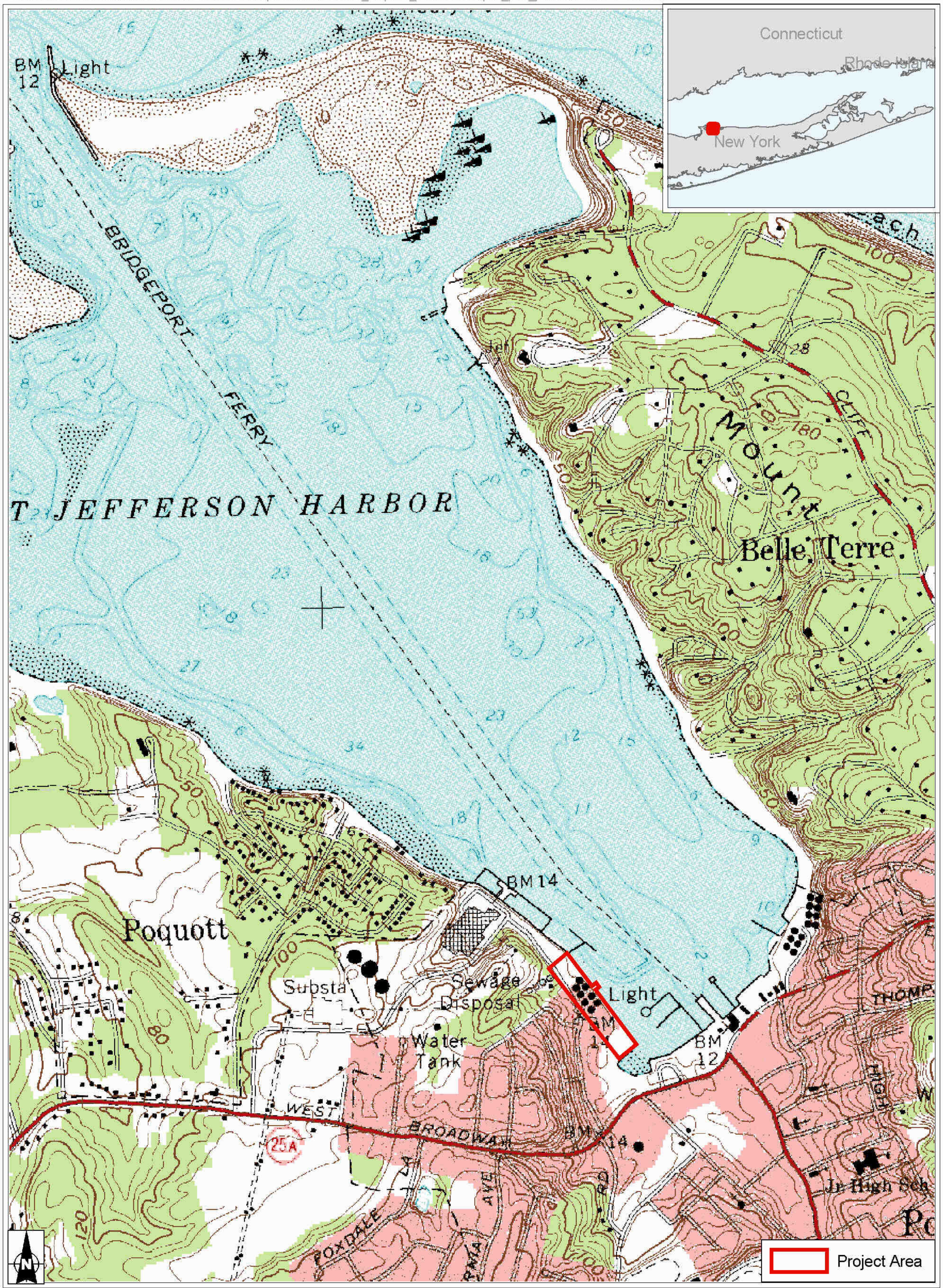
\\Bufsdl4\GIS\Pensacola\LNG\BROADWATER\Maps\MXD\Resource_Reports_Final\RR1\topos_port_jefferson.mxd 1/13/2006



Source: USGS Port Jefferson, 1967.

0 0.125 0.25 0.5
Miles

Figure 1-21 Proposed Onshore Facility Location
Port Jefferson, New York

Table 1-6 List of Federal Permits, Approvals and Consultations

Agency	Act	Permit/Approval
FERC	• Natural Gas Act (NGA) 15 U.S.C. 717 et seq., 18 CFR Part 153, Subpart B (2002)	• Sections 3 and 7 approvals to site, construct and operate the LNG terminal and to construct and operate the subsea connecting pipeline facilities, including the pipeline riser and mooring tower, respectively
USCG	• The Maritime Transportation Security Act of 2002 • 33 CFR § 127	• Review process – project must be compatible with National and Area Marine Security Plans • Letter of Recommendation
Advisory Council on Historic Preservation	• National Historic Preservation Act, Section 106	• Review of project effects on cultural resources
EPA	• Clean Water Act, Section 401 and 404 • Clean Air Act	• Review of Section applications • Prevention of Significant Deterioration, New Source Review
NOAA Fisheries	• Marine Mammal Protection Act, 16 U.S.C. 1361 et seq. • Magnuson-Stevens Fisheries Conservation and Management Act – Sustainable Fisheries Act • National Fishing Enhancement Act of 1984	• Consultation • Consultation regarding Essential Fish Habitat • Consultation regarding the National Artificial Reef Plan and commercial/recreational fisheries
USACE	• Clean Water Act (CWA), 33 U.S.C. § 1344 et seq. • Rivers and Harbors Act of 1899 (RHA) 33 U.S.C. § 403 et seq.	• Section 404 – dredge and fill permits • Section 10 permit
USFWS	• Marine Mammal Protection Act, 16 U.S.C. 1361 et seq.	• Consultation
Federal agencies	• National Environmental Policy Act (NEPA) 42 U.S.C. § 4321 et seq., particularly 42 U.S.C. § 4332, 40 CFR Part 1500	• Procedural statute, not a permitting statute. Requires federal agencies to consider environmental impacts of proposed action
Federal agencies consultation with USFWS and NOAA Fisheries	• Section 7, Endangered Species Act, 16 U.S.C. 1531 et seq.	• Consultation regarding federally listed threatened or endangered species. If potential adverse impact identified, then a Biological Opinion must be issued by responsible agency. Primarily a procedural statute. No permit required unless an incidental take of protected species is involved (then Section 10 permit required)
FAA	• 49 CFR Part 77	• Review of construction or alteration that might affect navigable airspace

Table 1-7 List of State Permits and Approvals

Agency	Act	Permit/Approval
NYSDEC	• Clean Water Act 33 U.S.C. § 1342(a) – delegated from EPA • Clean Water Act 33 U.S.C. § 1341 • Clean Air Act Title V 40CFR 70 – delegated from EPA; implementing NYS regulations: 6 NYCRR 201 • 6 NYCRR Part 596	• State Pollution Discharge Elimination System (SPDES) permit • Section 401 – State certification of water quality • Certificate to operate air contamination sources • Bulk Storage Permit
NYSDOS	• New York State Coastal Zone Management Act - delegated from the Federal DOC	• Coastal Zone Consistency Determination
NYSDPS	• Natural Gas Pipeline Safety Act, 49 U.S.C. §§ 60101, et seq. (2000) - as agent for USDOT OPS	• Requirement to certify that Broadwater will design, install, inspect, test, construct, operate, replace, and maintain a gas pipeline facility under the standards and plans for inspection and maintenance under section 60108 of 49 U.S.C. §60108.
NYSOGS	• New York Public Lands Law	• Submerged Lands easement/lease
NYSOPRHP	• Section 106, National Historic Preservation Act	• Review of project effects on cultural resources

Permit applications will be submitted after Broadwater's FERC filing so as to provide sufficient review and processing times for the respective jurisdictional agencies and to allow the Project to be operational by 2010.

1.8.1 Agency Consultations

On November 9, 2004 Broadwater submitted a request to the FERC for authority to use the NEPA Pre-filing process. In its request Broadwater indicated its commitment to:

- effective stakeholder engagement throughout the life of the project;
- identifying all stakeholder issues or concerns regarding the Project;
- resolving such issues before filing the application; and
- providing the FERC with a complete application.

On November 29, 2004 the FERC issued its approval of the Pre-filing review request and established pre-file Docket No. PF05-4-000. On January 18, 2005 a "start up" meeting was held between the FERC and Broadwater, and on February 11, 2005 the FERC issued a public notice of the Pre-filing Process Review. Since then Broadwater has engaged in ongoing consultation with the FERC in teleconferences and face to face meetings.

On August 11, 2005 the FERC issued a Notice of Intent to Prepare an Environmental Impact Statement and announced its plan to hold public meetings on Long Island and in Connecticut. The public meetings were held jointly with the USCG in conjunction with its review of the safety and security of the Project.

Broadwater has also engaged in ongoing discussions with other federal and state permitting agencies regarding project feasibility, issue identification, mitigation strategies, as well as to determine permitting requirements.

1.8.2 Public Consultations

Broadwater's communications plan is designed to solicit feedback from all interested stakeholders so that concerns are understood and addressed. From its inception, Broadwater sought the assistance of various individuals in assessing project feasibility including identifying key stakeholders, issues and potential mitigation strategies. Those discussions provided Broadwater with the meaningful feedback it required to proceed with its application for NEPA Pre-filing review.

Broadwater publicly announced the Project on November 9, 2004. On that date Broadwater opened its project office in Riverhead, Suffolk County, New York for face to face contact and as a repository for Project information, activated its Project website, and announced its single point of contact for stakeholder communication.

Since the public announcement Broadwater has undertaken to identify all stakeholder issues or concerns regarding the Project and to address such issues before filing the FERC application.

Broadwater's continuing communications plan has included the following elements:

- Individual outreach through the distribution of Project information by face to face meetings, telephone contact and mailings to project stakeholders, including the general public, elected and non-elected officials, non-governmental organizations, academics, industry groups, civic associations, and local and regional media; and

- Expanding its outreach efforts through regularly updating its website with Project information and by conducting open houses. This has including a series of open houses on Long Island and in Connecticut in November and December 2004 and in April 2005 on Long Island.

1.9 AFFECTED LANDOWNERS

All lands underlying state waters fall under the ownership of the state of New York. Broadwater will require an easement from the New York State Office of General Services for the mooring tower and pipeline.

1.10 NONJURISDICTIONAL FACILITIES

Broadwater is not aware of any non-jurisdictional facilities associated with this Project.

1.11 REFERENCES

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APPENDIX A

REGIONAL MARKET GROWTH AND THE NEED FOR LNG IMPORTS INTO THE NORTHEAST U.S. AND EASTERN CANADA

ENERGY AND ENVIRONMENTAL ANALYSIS, INC.

REGIONAL MARKET GROWTH AND THE NEED FOR LNG IMPORTS INTO THE NORTHEAST U.S. AND EASTERN CANADA

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October 13, 2005

ABOUT ENERGY AND ENVIRONMENTAL ANALYSIS, INC.

Energy and Environmental Analysis (EEA), located in metropolitan Washington, D.C., is a nationally recognized consulting firm offering technical, analytical, and management consulting services to a diverse clientele. Founded in 1974 to perform economic, engineering, and policy analysis in the energy and environmental fields, EEA has exhibited leadership and innovation in investigating energy and environmental issues.

DISCLAIMER

This report includes forward-looking statements and projections. Energy and Environmental Analysis, Inc. (EEA) has made every reasonable effort to ensure that the information and assumptions on which these statements and projections are based are current, reasonable, and complete. However, a variety of factors could cause actual results to differ materially from the projections, anticipated results or other expectations expressed in this report, including, but not limited to, general economic and weather conditions in geographic regions or markets that may affect the gas market.

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Abbreviations

Tcf – Trillion cubic feet

Bcf – Billion cubic feet

Bcfd – Billion cubic feet per day

MMcf – Million cubic feet

MMcfd – Million cubic feet per day

MMBtu – Million British Thermal Units

TWh – Terawatt-hours

GW – Gigawatt

MW – Megawatt

MDthd – Thousand Decatherms per day

$/Dth – Dollars per Decatherm

$/MMBtu – Dollars per Million British Thermal Units

NEEC – New England and Eastern Canada geographical region

1 EXECUTIVE SUMMARY

The North American natural gas market has undergone a fundamental shift over the past few years. A relatively tight balance between gas supply and demand has developed, creating relatively high and volatile gas prices. Growing gas consumption in power generation coupled with relatively static gas supply is the main reason for the shift in the natural gas market. Since 2000, gas prices throughout North America have averaged nearly $5 per MMBtu and have exhibited significant volatility, unlike gas prices in the 1990s that were fairly constant between $2 and $3 per MMBtu. This trend is expected to continue. For the foreseeable future, access to new natural gas supplies will become increasingly important.

As gas production from mature North American basins declines over time, new frontier gas sources must be developed to satisfy the anticipated 10 Tcf of incremental growth in gas consumption (Table 1). This points toward the importance of LNG imports. Total U.S. and Canadian LNG imports are projected to significantly increase from today's level of approximately 2 Bcfd to over 25 Bcfd by 2025. A positive environment for LNG imports is foreseen, and the market should easily support LNG from a variety of new sources over time.

Within the U.S. and Canada, the Northeast U.S. and Eastern Canada (NEEC) are among the most attractive markets for LNG imports. The area currently accounts for 14 percent of total gas use in the U.S. and Canada with over 3.5 Tcf of annual consumption, and like the rest of North America, the area's gas consumption for power generation is likely to grow significantly in the foreseeable future. The area's total gas consumption is expected to grow by 1.5 percent annually, with total annual consumption reaching nearly 5 Tcf by 2015.

Table 1
Projected Natural Gas Consumption (Bcf per Year)[1,2]

Source: Energy and Environmental Analysis, Inc.

Northeast U.S. and Eastern Canada

Sector	2004	2010	2015	2020	2025	2004-2015 Delta	2004-2015 Annual % Growth	2004-2025 Delta	2004-2025 Annual % Growth
Residential	1,116	1,171	1,236	1,301	1,336	120	0.9%	220	0.9%
Commercial	879	930	1,002	1,065	1,101	124	1.2%	222	1.1%
Industrial	842	863	969	978	1,037	127	1.3%	195	1.0%
Power Generation	619	1,177	1,477	1,521	1,237	858	8.2%	617	3.3%
Other	79	96	88	93	94	9	1.0%	15	0.8%
	3,535	4,237	4,772	4,957	4,804	1,238	2.8%	1,269	1.5%

Total U.S. and Canada

Sector	2004	2010	2015	2020	2025	2004-2015 Delta	2004-2015 Annual % Growth	2004-2025 Delta	2004-2025 Annual % Growth
Residential	5,519	5,966	6,282	6,631	6,796	763	1.2%	1,277	1.0%
Commercial	3,509	3,703	3,925	4,138	4,232	416	1.0%	723	0.9%
Industrial	8,532	8,357	8,596	8,774	9,302	64	0.1%	769	0.4%
Power Generation	4,953	8,091	11,001	12,175	12,419	6,048	7.5%	7,467	4.5%
Other	2,432	2,494	2,599	2,591	2,550	167	0.6%	118	0.2%
Total	24,945	28,611	32,403	34,309	35,299	7,458	2.4%	10,354	1.7%

Current gas consumption in New York City, Long Island and Southern Connecticut, markets that would be directly connected to Broadwater, is approximately 700 Bcf per year, or just under one-fifth of the total NEEC market (Table 2). Recent market growth has averaged 2.7 percent per year. Similar to the region as a whole, most of the growth in gas consumption in this area has been driven by the power generation sector. In the past ten years, annual power sector gas consumption has increased by 100 Bcf. Annual growth rates for the power sector have averaged 5.6 percent.

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[1] All projections are based on the EEA March 2005 Base Case with a 1 Bcfd capacity Broadwater LNG terminal added. See Section 4 for Case assumptions and discussion.

[2] Note that historical (i.e., 2004 and before) values shown throughout this report are from EEA's historical backcast from its modeling. In its modeling, EEA places all cogenerating and IPP power generating facilities built prior to 1998 in the industrial sector. The U.S. Energy Information Administration reports all IPP generating facilities in the power sector in its publications, including IPP units built prior to 1998. The reader should keep this in mind when comparing historical data reported by EEA and EIA.

Table 2
Historical Gas Use in New York City, Long Island, and Southern Connecticut (Bcf per Year)

Source: Energy and Environmental Analysis Inc. Historic Market Backcast.

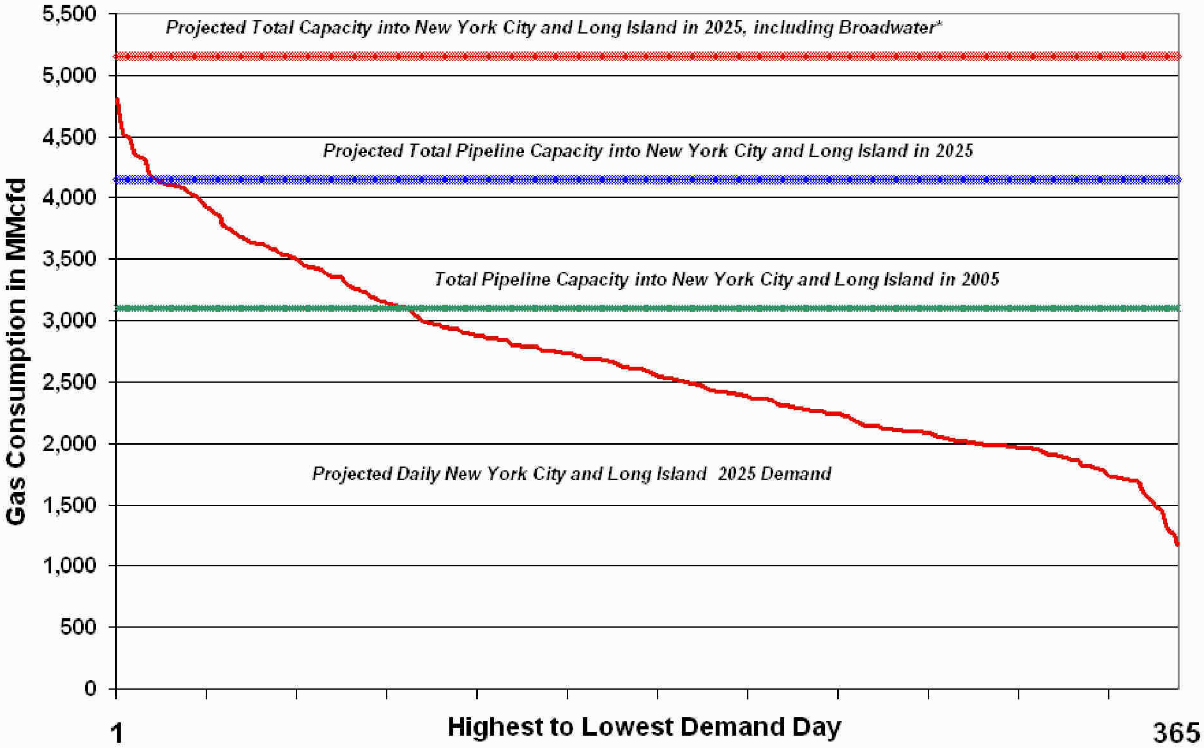
	Residential	Commercial	Industrial	Power Generation	Total End-Use
1995	231	89	45	160	525
1996	249	96	45	158	547
1997	233	120	47	174	573
1998	207	117	46	160	531
1999	226	122	48	232	628
2000	241	127	47	241	656
2001	222	121	38	236	617
2002	227	122	39	303	691
2003	256	127	36	257	675
2004	245	123	37	260	664
Annual % Growth	0.6%	3.6%	-2.1%	5.6%	2.7%
% of Total, 2004	37%	18%	6%	39%	100%

In an environment of increasing gas consumption, LNG imports will become an important source of gas supply for the area's consumers. Consumers would benefit in a number of ways from a new Broadwater facility. First, LNG supplies are a needed diversification to the supplies that originate in Western Canada and the Gulf Coast. Currently, Western Canada and Gulf Coast supply 85 percent of the gas consumed in the area. LNG imports at Broadwater and other NEEC locations could potentially reduce that level to 60 percent. A Broadwater facility may reduce the need for future long-haul transportation infrastructure that has proven difficult to build into the New York and New England gas markets.

Second, incremental LNG imports directly to the New York City area could potentially enhance gas and electric reliability in the area. At peak send-out, Broadwater would supply enough gas to fuel 5,800 MW of gas-fired capacity, which equates to 50 percent of the gas-fired capacity in New York City, Long Island, and Southern Connecticut. Pipeline infrastructure is currently stressed to its limits on cold winter days. An additional 1 Bcfd of new pipeline capacity is projected to be needed to meet incremental peak demand growth in New York City by 2025 (Figure 1). Incremental supplies from Broadwater will increase the level or reliability of gas delivered to the New York City area.

Figure 1
Buffer Created by Broadwater Supplies on Pipeline Utilization During Peak Periods

Source: Energy and Environmental Analysis, Inc.



* This is the upper boundary on total capacity, assuming the full 1,000 MMCfd of peak supply capability from Broadwater is available to New York City and Long Island.

Our analysis suggests that LNG providers should be excited about the opportunity to deliver gas into the Northeast U.S. and Eastern Canada. As stated above, the area is a large consumption area, accounting for 14 percent of total gas consumed in the U.S. and Canada. Hence, the market is deep. It is also broad among different consumer classes, with no single sector or class of consumers (i.e., residential, commercial, industrial, and power providers) dominating gas consumption. There are many large gas utilities, power plants, and industrial facilities that consume large amounts of gas in the area. Hence, a LNG provider should not be concerned about market concentration among gas purchasers. In short, the market is a broad and deep market with good growth potential and significant ability to absorb large amounts of imported LNG.

2
INTRODUCTION

The North American natural gas market has undergone a fundamental shift that started at the beginning of this decade. From the years 2000 through 2004, wellhead gas prices at many locations throughout North America have averaged nearly $5 per MMBtu and have also exhibited significant volatility, unlike prices in the 1990s that were fairly constant at between $2 and $3 per MMBtu. This leads to the conclusion that the North American natural gas market is in a new era.

In this new era, the supply and demand balance for natural gas is much tighter than it was in the 1990s. Throughout most of the 1990s, a gas bubble existed in the North American natural gas market. During the period, productive capacity for natural gas exceeded gas production, or the amount of gas necessary to satisfy gas consumption at prevailing market prices. The gas bubble that existed during the 1990s was created during the regulated market environment that existed for natural gas during the 1970s and early 1980s. By and large, the bubble was created during the oil boom that occurred in the U.S. in response to two different oil price shocks that had occurred in the 1970s.

> … the North American gas market is in a new era where natural gas prices will remain relatively high and volatile at many locations, creating significant opportunity for imported LNG.

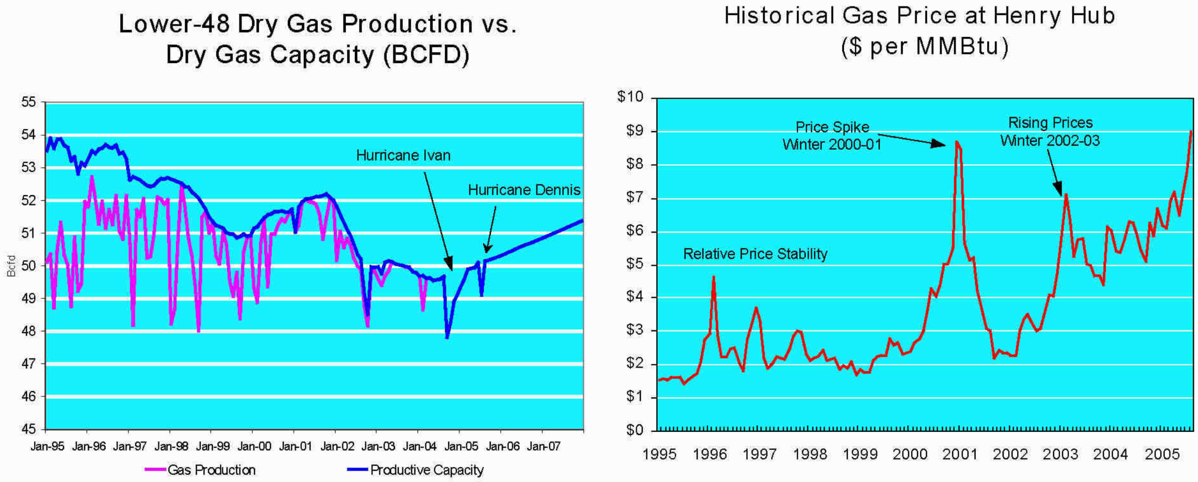
Figure 2 shows that the trends for U.S. gas production and productive capacity have diverged in recent years, and the result has been the bursting of the gas bubble that kept prices relatively low and constant throughout the 1990s. After 2000, gas producers in the U.S. have produced at capacity. In this environment, there is little shut-in gas supply and little gas-on-gas competition between producers willing to bid the price down towards variable cost to sell their excess supply. The result has been much higher gas prices. Also, the lack of excess productive capacity has contributed to the levels of price volatility that have been recently observed. The market has a less flexible gas supply ready to satisfy gas demand during cold winter weather episodes and hot summer weather episodes.

In the current market environment that is likely to persist for some time, LNG imports are rapidly becoming an attractive supply source to many U.S. and Canadian gas consumers. Many analysts and energy industry observers are now beginning to recognize the growing crisis brought about by waning gas supply, and are seeking solutions. Therein lies the importance of LNG imports, a potentially abundant low-cost source of gas supply for the future.

Recognizing the growing importance of LNG imports, TransCanada has requested that EEA provide a study on the need of LNG imports in the Northeast U.S. and Eastern Canada.

Figure 2
Recent Historical Trends for Productive Capacity, Production, and Gas Prices

Source: Energy and Environmental Analysis, Inc.



Divergent trends in gas supply and demand have led to a tight balance between supply and demand, higher gas prices, and increased price volatility.

Section 1 above provided an executive summary of the main findings and results in this study. The third section immediately following this introduction provides a broad overview of the Northeast U.S. and Eastern Canada gas markets. The fourth section provides a forecast of gas demand for the Northeast U.S. and Eastern Canada gas markets and the assumptions used to reach those projections. The fifth section provides a more focused analysis on the New York City area, which would be home to the new Broadwater LNG import facility. Finally, Section 6 discusses the potential importance of imported LNG for gas and electric reliability.

3
OVERVIEW OF THE NORTHEAST U.S. AND EASTERN CANADA GAS MARKETS

This section provides an overview of the Northeast U.S. and Eastern Canada (NEEC) gas markets. The area includes the U.S. states of Pennsylvania, New Jersey, New York, Maine, New Hampshire, Vermont, Massachusetts, Connecticut, and Rhode Island, and the Canadian provinces of Quebec, New Brunswick, Newfoundland, and Nova Scotia. The area is home to one of the five current LNG import facilities in North America, the Everett LNG import facility located near Boston, Massachusetts.

3.1 Review of Pipeline and Storage Infrastructure

3.1.1 Pipelines in the Northeast U.S and Eastern Canada

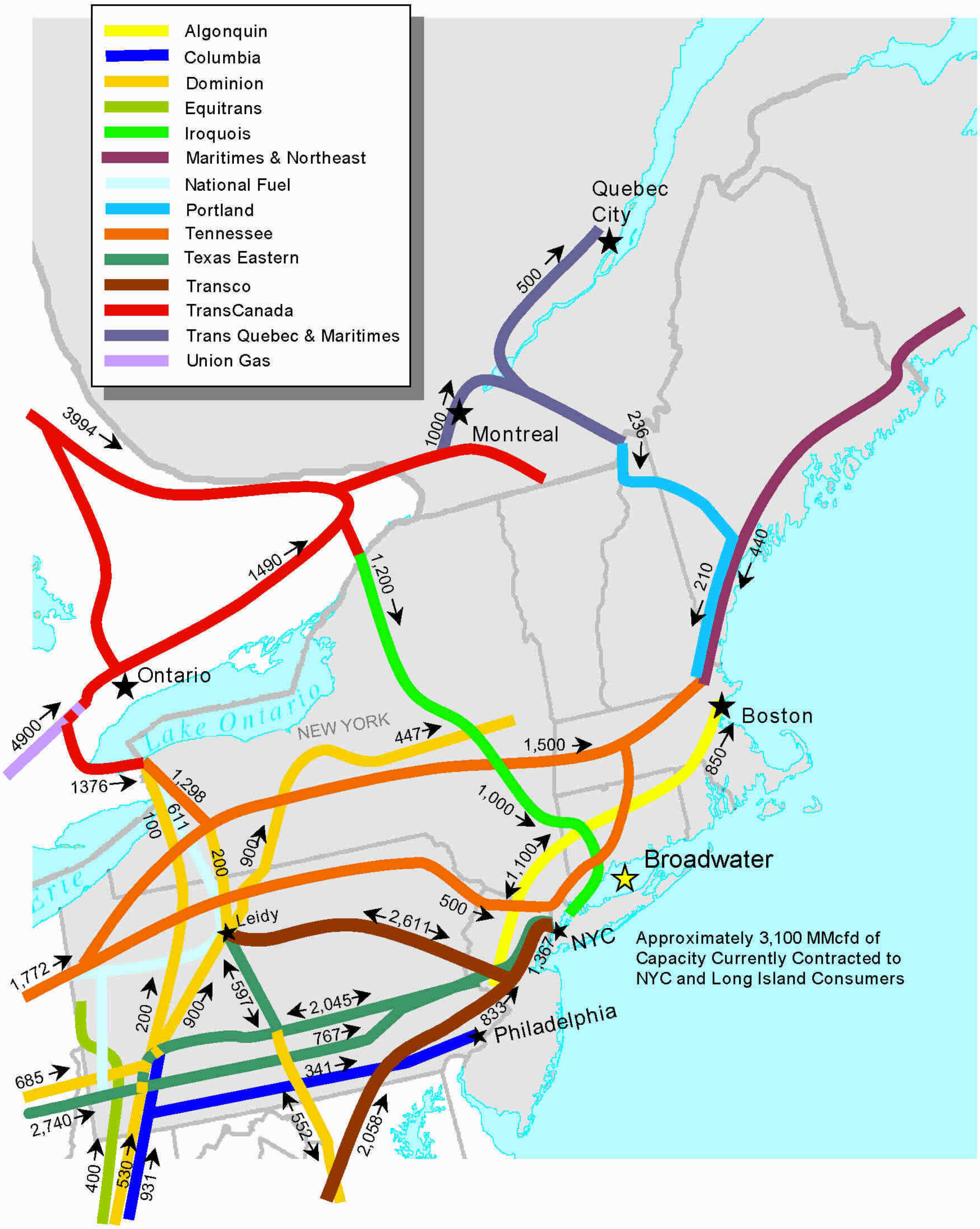
The NEEC market area has historically relied on gas delivered from other areas via an extensive pipeline network that has been developed over many years. Fourteen major pipelines transport gas in the area (Figure 3), and there is a total of over 15 Bcfd of capacity entering the area. The characteristics for each of the pipelines serving the region are summarized below.

- • Transco, owned and operated by Williams, is one of the largest pipes in the area with over 2 Bcfd of capacity entering from Maryland into southern Pennsylvania. This pipeline is generally characterized as a long-haul pipe, delivering gas that originates in the Gulf of Mexico into the area. In Pennsylvania, Transco also provides the capability to move gas into and out of storage in western Pennsylvania via its Leidy lateral that runs from the Leidy storage fields to an interconnect with its Gulf Coast Mainline in New Jersey. The pipe is the largest provider of gas deliveries into the New York City area with over 1 Bcfd of capacity crossing from New Jersey into New York City. Transco has about 1.2 Bcfd of firm contracts with New York delivery points.

Fourteen pipelines with over 15 Bcfd serve NEEC. Pipeline capacity into New York City and New England is much more limited.

Figure 3
Major Pipelines Into and Out of the Northeast U.S. and Eastern Canada

Source: Energy and Environmental Analysis, Inc.[3]



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[3] Based on a compilation of pipeline EBB data and other sources.

- • Maritimes and Northeast Pipeline (MNP) provides a direct link for natural gas production in Eastern Canada, primarily offshore production near Sable Island to the New England markets. MNP terminates at Dracut, Massachusetts at an interconnect with Tennessee Pipeline. MNP has 440 MMcfd of capacity at the Canada/U.S. border. In Southern Maine, MNP interconnects with the Portland Natural Gas Transmission System (PNGTS). System capacity from the PNGTS interconnect to Dracut, which is jointly owned by the two pipelines, is 650 MMcfd.

- • Texas Eastern, owned and operated by Duke Energy, is another of the largest pipes in the area with 2.7 Bcfd of pipeline capacity entering into the area from Ohio. Like Transco, Texas Eastern is characterized as a long-haul line that originates in the Gulf of Mexico. Even though it follows a different path from the Gulf Coast into the Northeast, it is similar to Transco in a number of respects. Namely, it ties significant capacity into storage within the NEEC area. It also is a large provider of capacity into the New York City area, with over 700 MMcfd of capacity under contract to consumers in the area.

- • Tennessee Pipeline, owned and operated by El Paso Corporation, is another of the largest pipes in the area with nearly 1.8 Bcfd of capacity entering from Ohio. It is the major conduit to carry Gulf Coast supplies to New England. Tennessee also receives gas from the TransCanada system at the U.S./Canada border near Niagara Falls, New York. Tennessee, like the other pipes in the area, ties to storage throughout the area.

- • Columbia Gas Transmission is a local transmission line in the area. The pipeline has numerous spurs and laterals, much like a distribution system, even though it is an interstate pipeline. Columbia Gas Transmission receives almost all of its gas supply from Columbia Gulf Transmission through interconnects at the Kentucky/West Virginia border. Columbia Gas Transmission currently has over 1.4 Bcfd of pipeline capacity under contract throughout the Northeast U.S.

- • Like Columbia Gas Transmission, Dominion Pipeline is a local transmission line in the area. Also like Columbia Gas Transmission, the pipeline has numerous spurs and laterals. Dominion has numerous interconnects with many of the other pipelines in the area, through which it receives a significant portion of its gas supply. Dominion's production affiliate is also a major supplier for shippers on the Dominion Pipeline. Dominion's system has a capacity of over 1.2 Bcfd, and an expansion planned concurrently with an expansion of the Cove Point LNG import facility will increase Dominion's capacity to nearly 1.8 Bcfd.

- • Like Columbia Gas Transmission and Dominion Pipeline, National Fuel is an interstate transmission line with deliveries only in the Northeast U.S. The pipeline has numerous spurs and interconnects with other pipes. National Fuel currently has a capacity of about 600 MMcfd serving consumers mostly located in western New York. National Fuel also ties into a large amount of storage close to the U.S./Canada border near Niagara Falls, New York.

- • Equitrans, running from West Virginia to western Pennsylvania, is one of the smaller interstate transmission lines in the area with about 400 MMcfd of capacity.

- • Iroquois Pipeline, one of the newer gas transmission lines in the area, enters into NEEC in northeast New York from an interconnect with TransCanada PipeLines at the U.S./Canadian border, from which it receives almost all of its gas supply. Hence, Western Canadian production presently accounts for most of the gas flowing on Iroquois Pipeline. The line runs south over a significant distance before crossing into New England. From there, it runs directly south to New York City, delivering gas in Massachusetts, Connecticut, and New York City. The line currently has 1.2 Bcfd of capacity under contract to New England and New York consumers, of which approximately 1 Bcfd is under contract to consumers in New York City, Long Island, and Southern Connecticut.

- • Algonquin Natural Gas Transmission, owned and operated by Duke Energy, runs from interconnects with Texas Eastern, Transco, Columbia, and Tennessee in New Jersey northeast into the New England states. With 1,100 MMcfd of capacity into New England, and about 850 MMcfd of capacity into the Boston area, Algonquin is the second largest transmission option for New England gas consumers.

- • Portland Natural Gas Transmission System. PNGTS provides about 240 MMcfd of capacity entering New England from Quebec. PNGTS gas flows from the Trans Quebec and Maritimes pipeline prior to the interconnect with PNGTS at the U.S. / Canada border. PNGTS interconnects with the Maritimes and Northeast Pipeline to the north of Boston. PNGTS serves several gas-fired power generation facilities in New Hampshire and Maine, and provides an additional transport option for the Boston area. Currently, PNGTS is fully contracted, but typically flows full only during the coldest winter days. There has been consideration of reversing flow on PNGTS to accommodate flows of Eastern Canadian production into Quebec. Recently, there has been discussion of reversing flow to transport LNG delivered in Maine or the Canadian Maritimes provinces into Quebec.

- • Currently, Quebec is served solely via the Trans Quebec and Maritimes (TQM) pipeline. This pipeline connects with TransCanada PipeLines to the west of Montreal, and carries natural gas to Montreal, Quebec City, and the border interconnect with the Portland Natural Gas Transmission System. TQM has a capacity of approximately 1 Bcfd.

- • Currently, all of the natural gas flowing into Quebec and the natural gas flowing into New England via the TQM, PNGTS, and Iroquois pipelines flows through eastern Ontario on the TransCanada PipeLines (TCPL) system. Much, although not all of this gas originates in Alberta, and flows into Ontario via the TransCanada mainline, or through capacity held by TCPL on the Great Lakes Pipeline and the Union Gas Pipeline systems.

3.1.2 Summary of Pipeline Capacity Serving Northeast U.S and Eastern Canada

In summary, there are fourteen major pipelines with over 15 Bcfd of pipeline capacity entering NEEC. Pipelines in Pennsylvania, Western New York, New Jersey, and Eastern Canada not only serve local gas consumption but also are conduits for downstream markets. Therefore, pipeline capacities within these regions exceed local needs, which adds flexibility.

Pipelines entering the New York City area and the southern New England states are at the "end of the line" of the interstate pipeline system. Except for Algonquin Natural Gas Transmission, which provides gas transmission between New York and Boston, flow on pipelines is only into the region. Therefore, these markets have relatively less flexibility and are more susceptible to constraints. Based on firm transportation commitments, capacity into the New York / Long Island area is approximately 3.1 Bcfd. Firm contracted capacity into Southern Connecticut is just under 900 MMcfd.

3.1.3 Storage Serving the Northeast U.S and Eastern Canada

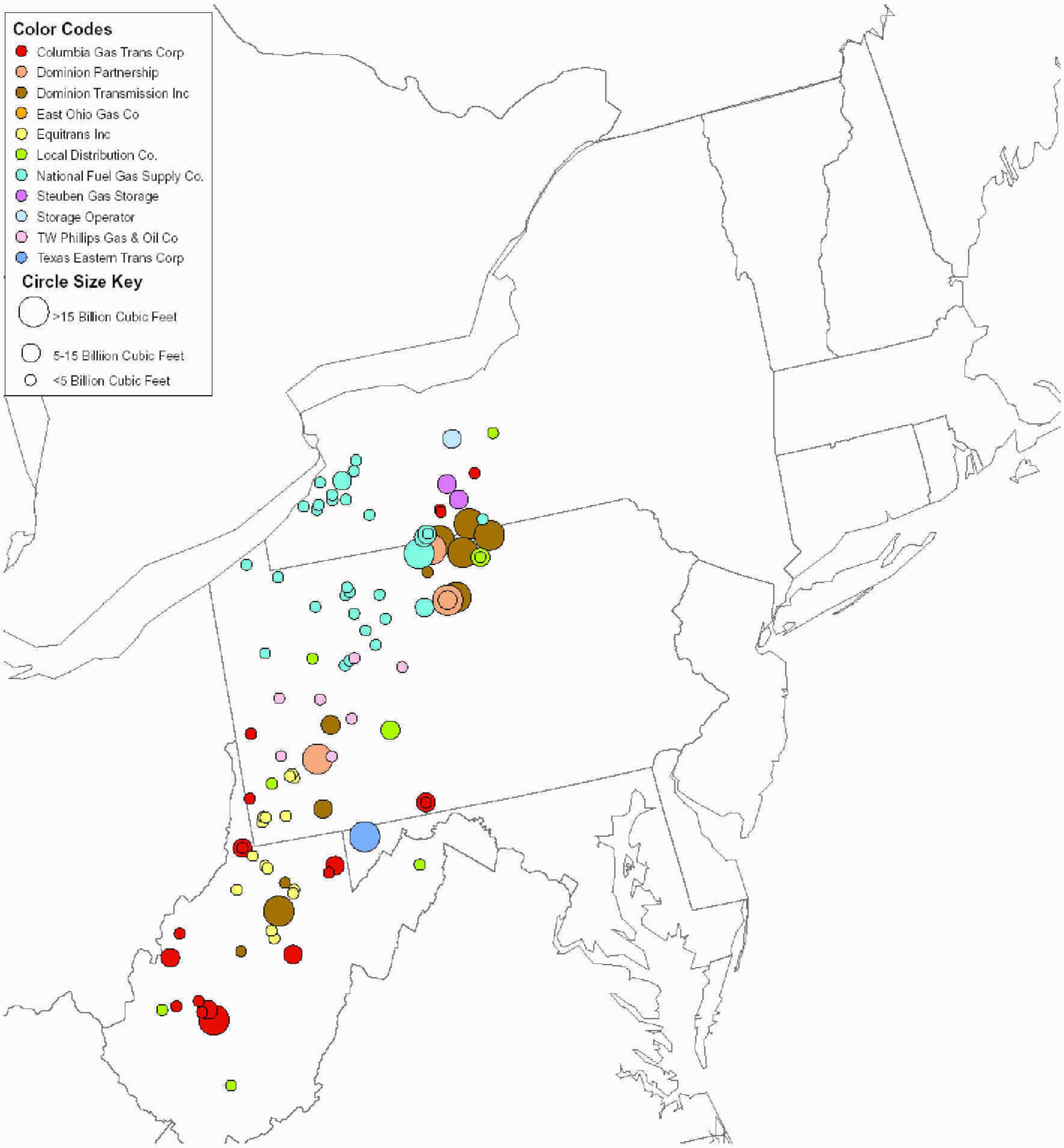
Most of the storage fields serving NEEC markets are located in an area between West Virginia and Western New York in the Appalachia Basin (Figure 4). The region has an underground storage capacity of 730 Bcf with a peak deliverability of 12.5 Bcfd (Table 3). With over 400 Bcf or 55 percent of the total storage capacity, Pennsylvania has the largest amount of capacity of all states in the area. Although West Virginia is not part of NEEC, most of its storage is used to balance loads in NEEC. In short, West Virginia has a total storage capacity of 200 Bcf and accounts for a large portion of total storage capacity serving NEEC.

The largest storage operator in the area is Dominion with roughly 200 Bcf of capacity that it owns directly and another 200 Bcf of capacity that it owns in partnerships with Duke, Texas Eastern, and Transco. Dominion's storage fields have a peak day deliverability of nearly 7 Bcfd. Columbia Gas is the second largest operator with a total of just over 100 Bcf of storage capacity and 2.2 Bcfd of peak day deliverability. Together, these two companies operate over 70 percent of the working gas capacity and peak deliverability in the region.

Based on capacity, National Fuel is the largest of the remaining owners in the area with over 90 Bcf of storage capacity and 880 MMcfd of deliverability. Storage fields operated by Equitrans have similar deliverability at 740 MMcfd, but have much smaller working gas capacity at 27 Bcf. Such capacity is well suited for higher quality storage services like hub balancing and load following, services that have great value in an environment where gas-fired power generation is growing. The remaining storage owners control just over 80 Bcf of working gas capacity and nearly 1.5 Bcfd of deliverability.

Figure 4
Storage Fields Serving Markets in the Northeast U.S. and Eastern Canada

Source: Energy and Environmental Analysis, Inc. representation of storage information provided by the Energy Information Administration and American Gas Association.



The largest storage fields serving NEEC are concentrated in a few different areas. Most notably, many large fields are concentrated around the Leidy Hub. The majority of the large fields in this area are owned and operated by Dominion. Stored gas from these fields has a number of different transmission options, most notably Transco, Dominion, and National Fuel. Outside of this area, there are a number of other large fields scattered throughout, but mostly in West Virginia and Southwest Pennsylvania.

Table 3
Underground Natural Gas Storage Serving Markets in the Northeast U.S. and Eastern Canada by Operator

Source: Summary of Storage Statistics provided by the Energy Information Administration and the American Gas Association.

By Operator	2004 Working Gas Capacity (Bcf)	Peak Deliverability (MMcfd)
Dominion Transmission	211	4,050
Dominion Partnerships[4]	195	2,880
Columbia Gas	108	2,170
National Fuel	92	880
Equitrans	27	740
Texas Eastern	15	310
All Others	81	1,460
Total NEEC	730	12,490

[4] Dominion's ownership share is about 50 percent across all partnerships.

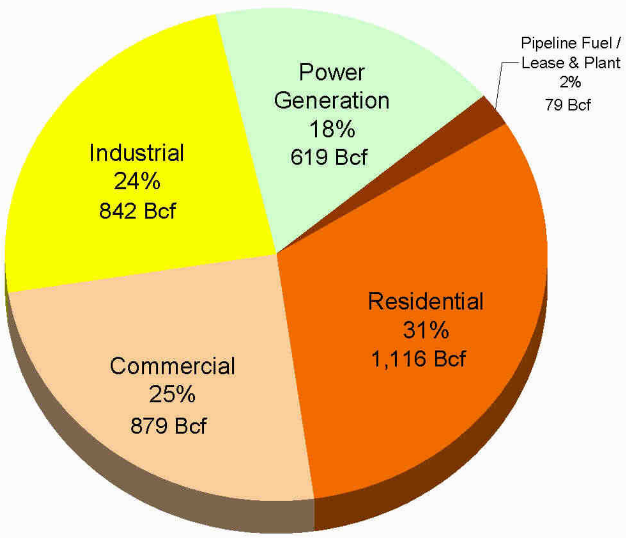
3.3 Historical Gas Consumption

NEEC has recently had about 3,500 Bcf of gas consumption annually, an ample level to support significant LNG imports.

Total consumption in the Northeast U.S. and Eastern Canada for 2004 was 3,500 Bcf (Figure 5). Nearly 2,000 Bcf, or 56 percent was concentrated in the residential and commercial sectors. The industrial sector accounted for nearly a quarter of gas consumption at about 840 Bcf. The power generation sector consumed 18 percent of the 2004 load, or over 600 Bcf. Pipeline fuel and lease and plant (associated with Eastern Canadian offshore, Western New York, and Western Pennsylvania production) accounted for the remaining 2 percent of gas consumption.

Figure 5
Northeast U.S. and Eastern Canada Natural Gas Consumption by Sector for 2004

Source: Energy and Environmental Analysis Inc. Historic Market Backcast



NEEC's 2004 consumption was up by over 240 Bcf when compared to 1995 consumption (Table 4). Total end-use natural gas consumption in NEEC has been trending up by just under 1 percent per year during the past 10 years. Most of the increase can be attributed to the rapid increase of gas use for power generation, which has increased from 15 percent of the total regional natural gas consumption to about 18 percent during the period. This is due to increased reliance on new gas-fired generating capacity, similar to trends throughout North America.

As in the rest of North America, industrial demand, which had been rising through 2000, dropped sharply in 2001, corresponding with a significant increase in natural gas prices. From 2000 to 2001, industrial demand in NEEC dropped by about 200 Bcf per year, and has been hovering at about 850 Bcf per year since.

When adjusted for weather, commercial gas consumption has increased at a rate of just over 2 percent per year. The relatively high growth rate is due to several factors, including relatively high fuel oil prices and the growth of combined heat and power installations and distributed generation in the commercial sector. In contrast, the residential sector has grown at a relatively modest pace of 0.8 percent per year over the period.

Table 4
Historical Gas Consumption in the Northeast U.S. and Eastern Canada (Bcf per Year)

Source: Energy and Environmental Analysis, Inc. Historic Market Backcast

	Residential	Commercial	Industrial	Power Generation	Total End Use	Electricity Sales (Billions of kWh)
1995	1,038	720	981	476	3,214	653.2
1996	1,127	776	997	314	3,214	659.6
1997	1,071	876	986	328	3,261	661.1
1998	929	789	937	302	2,957	673.0
1999	1,019	840	969	440	3,267	687.3
2000	1,094	888	1,021	481	3,484	702.7
2001	1,009	837	836	487	3,169	714.2
2002	1,022	848	867	640	3,376	721.8
2003	1,165	909	815	604	3,492	735.5
2004	1,116	879	842	619	3,455	746.5
Average	1,059	836	925	469	3,289	695.5
APC /1	0.8%	2.2%	-1.7%	3.0%	0.8%	1.5%
Weather Adjusted APC /2	0.8%	2.0%	---	---	---	---

1. Average annual percent change.
2. Trendline change adjusted for difference from normal weather.

3.4 Historical Gas Supplies

Historically, NEEC has depended on gas from two major supply areas, the U.S. Gulf Coast and Western Canada. Over 60 percent of the region's gas supply comes from the Gulf Coast via long-haul pipelines. About one-third of the region's total supply is delivered from the Gulf Coast via the Texas Eastern / Tennessee / Dominion pipeline corridor. Another 20 percent of the supply comes to NEEC via the Transco pipeline, which is one of the largest providers of gas to the region, and 10 percent of supply is delivered on the Dominion / Columbia / Equitrans corridor. TransCanada delivers gas to the region primarily from Western Canada via its interconnects with TQM, Iroquois, Tennessee, National Fuel, and the Dominion pipelines. In total, TransCanada provides about 25 percent of the region's supply.

The balance of the region's gas supply comes from local production (including supplemental gas from sources such as landfills) and LNG imports. Ten years ago, local production accounted for only 3 percent of the region's total supply, but since production at Sable Island began in 2000, local production has grown to meet 10 percent of the region's gas supply. Similarly, LNG imports to Everett, the region's sole import terminal, were very small in 1995, accounting for less than 1 percent of the region's supply. However, import volumes have grown steadily, and as of 2004, imported LNG accounted for nearly 5 percent of the region's supply.

Historically, NEEC has relied on the U.S. Gulf Coast and Western Canada for the vast majority of its gas supply, areas that have recently shown signs of gas resource exhaustion.

Table 5
Historical Gas Supply for the Northeast U.S. and Eastern Canada (Bcf per Year)

Source: Energy and Environmental Analysis, Inc. Historic Market Backcast

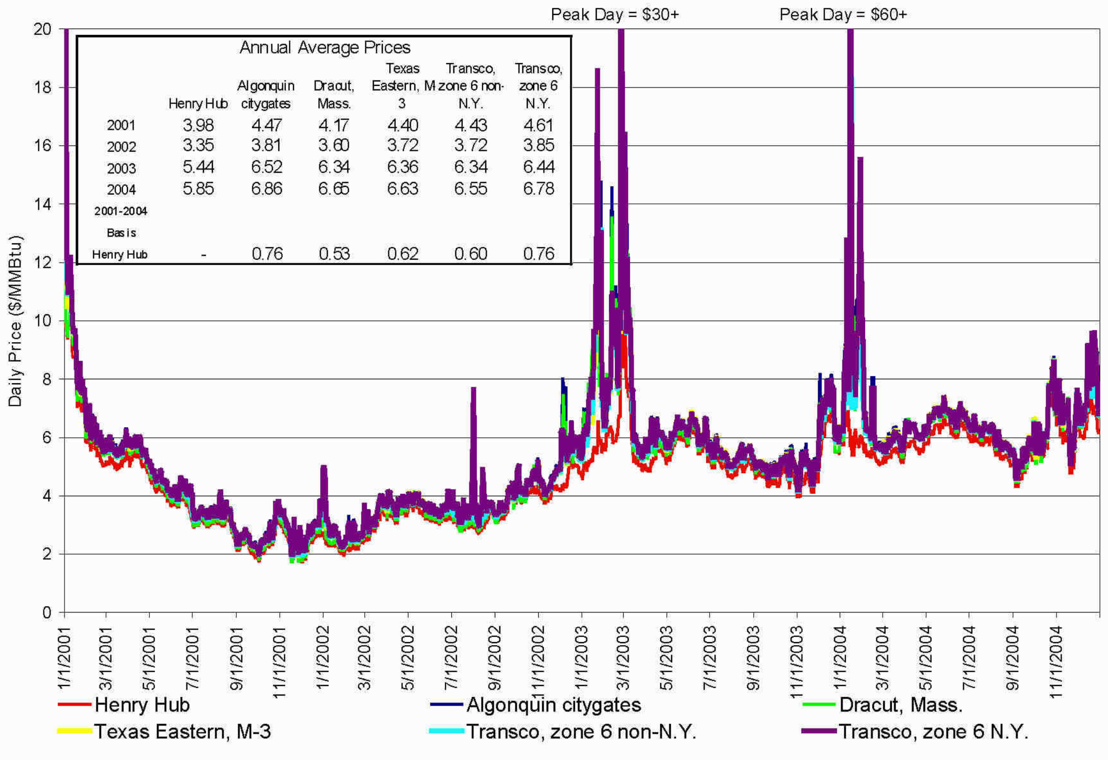
	Production and Supplemental Supplies	Transco	TransCanada	Dominion/ Columbia/ Equitrans (via WV)	Texas Eastern/ Tennessee/ Dominion (via Ohio)	LNG Imports	Total Supply
1995	123	642	983	328	1,171	13	3,260
1996	131	671	985	340	1,231	33	3,390
1997	160	665	977	333	1,162	47	3,344
1998	145	599	954	324	1,038	43	3,103
1999	156	631	1,006	343	1,123	96	3,355
2000	286	647	1,058	355	1,156	99	3,601
2001	358	640	889	342	1,079	97	3,405
2002	355	613	962	336	1,082	110	3,458
2003	357	687	911	373	1,215	164	3,707
2004	343	686	824	366	1,194	169	3,584
Average	241	648	955	344	1,145	87	3,421

3.5 Historical Gas Prices

In the past two years, natural gas prices at market centers in the Northeast U.S. have averaged in excess of $6 per MMBtu (Figure 6). As has been the case with prices throughout North America, prices have risen from the $2 to $3 per MMBtu level exhibited during the 1990s, and price volatility has increased during the past few years.

Within the area, New York City consumers have more often than not paid a substantial premium for gas, with basis from Henry Hub to New York City averaging 76 cents per MMBtu during the past four years (see Transco Z6 New York price). New England customers, as shown by the Algonquin Citygate prices, have paid similar premiums during the past four years. The premiums were actually higher relative to New York in 2003 and 2004. In areas before key bottlenecks in Northern New Jersey, the premiums have not been as large, but have still been substantial. For example, the Henry Hub to Dominion South Point and Columbia Appalachia pricing areas have recently exhibited a 20 to 35 cents per MMBtu basis (not shown), well below the New York City premium, but yet a significant premium. High price premiums indicate that parts of the pipeline system to the NEEC are often strained. Additional LNG imports would alleviate stress on pipelines to and within the NEEC.

Figure 6
Daily and Average Annual Natural Gas Prices in the Northeast U.S. and Eastern Canada ($'s per MMBtu)
Source: Platts Gas Daily



Annual Average Prices

	Henry Hub	Algonquin citygates	Dracut, Mass.	Texas Eastern, M 3	Transco, zone 6 non-N.Y.	Transco, zone 6 N.Y.
2001	3.98	4.47	4.17	4.40	4.43	4.61
2002	3.35	3.81	3.60	3.72	3.72	3.85
2003	5.44	6.52	6.34	6.36	6.34	6.44
2004	5.85	6.86	6.65	6.63	6.55	6.78
2001-2004 Basis Henry Hub	-	0.76	0.53	0.62	0.60	0.76

Price premiums relative to the Gulf Coast of 50 to 80 cents per MMBtu indicate that parts of the pipeline system to the NEEC are often strained. Additional LNG imports would alleviate stress on pipelines to and within NEEC.

4
GAS DEMAND PROJECTION IN THE NORTHEAST U.S. AND EASTERN CANADA

This section describes the assumptions behind the Energy and Environmental Analysis, Inc.'s (EEA's) Base Case to 2025. For this study, a 1.0 Bcfd Broadwater facility was added to EEA's base model assumptions beginning in November 2010 as per client's instructions. Projected natural gas consumption, sources of gas supply, and natural gas prices for NEEC are discussed.

4.1 Case Assumptions

Projections for this study have been produced with the EEA Gas Market Data and Forecasting System, a widely used model for the North American natural gas market (see Section 7 for more details). The key assumptions about the future that were used to create the forecast are summarized in Table 6.

The Base Case is a continuation of current conditions in the North American natural gas market well into the future. Most notably, the supply/demand balance for natural gas continues to remain tight, and natural gas prices remain relatively high over time compared to prices in the 1990s. North American natural gas demand continues to grow, led by robust growth in gas use for power generation that is required to satisfy incremental growth in electricity demand. Long-term crude oil prices moderate to $35.00 per barrel,[5,6] but are still high by historical standards. The relatively high oil prices tend to discourage significant gas-to-oil switching above current levels. In addition, it is assumed that gas-to-oil switching will continue to be limited by oil infrastructure[7].

The case assumes that 1 Bcfd of additional pipeline capacity is added into New England and New York City. More specifically, the case assumes that a 500 MMcfd "Millennium Light" project is completed in 2009 and an another 500 MMcfd generic pipeline expansion into New York City occurs in 2011. Although actual pipeline projects may

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[5] Real 2004$ price.

[6] The oil price input to EEA's model is the U.S. average refiners acquisition cost of crude (RAC) which generally is 5% to 10% below WTI, consistent with historical averages.

[7] A substantial amount of infrastructure, including refining, handling equipment, oil tanks, barges, and pipelines would be necessary to permit significant levels of oil burn in the power and industrial sectors. Obtaining the necessary environmental approvals and permits to burn significant amounts of oil would be a difficult and cumbersome task given the current environmental climate in North America.

differ, projects of similar size and timing are needed to meet anticipated area demand growth.

Table 6
Case[8] Assumptions

Environment	Assumptions
Natural gas supply/demand balance remains tight, providing a positive gas price environment for LNG imports. • U.S. and Canadian economies continue to grow at a modest pace, slightly lower than the average rate over the past two decades • Gas demand grows with the economy • Power generation gas load grows robustly as new gas power plants are relied on to satisfy growing electricity use • Gas supply in mature North American producing areas declines, prompting increased reliance on "new frontier" gas supplies	Long-term RAC oil price is $35.00 per barrel U.S. GDP +2.8 % per year, U.S. industrial production +2.3 % per year, and Canadian GDP +2.2 % per year Electricity use grows at 1.9 % per year Fossil fuel generation capacity: U.S. 2003-2025 gas power plant capacity grows by 180 GW (Net 90 GWs with retirements). Coal plant capacity grows by a net of 120 GW. Other generation: No new Hydro generation capacity. Nuclear power capacity increases 5 GWs by 2025 through efficiency gains at existing plants. Renewable generation increases by 50 GWs. Supply; traditional gas supplies struggle to keep up with demand growth, prompting increased reliance on "new frontiers". 1 Bcfd of Mackenzie Delta gas begins flowing in 2008. 4 Bcfd Alaska gas delivered to Canada and lower-48 U.S. beginning in 2014. 1.0 Bcfd Broadwater LNG terminal in New York begins operations in November 2010. Fully operational by January 2011. 1.5 Bcfd of LNG imports to NEEC by 2010. 4.2 Bcfd of LNG imports to NEEC by 2015. 4.2 Bcfd of LNG imports to NEEC by 2025. Pipelines and storage constructed as justified. Notably, 1 Bcfd of additional capacity added to New England and NYC. "Millennium Light" built at 500 MMcfd in 2009 and "generic" capacity 500 MMcfd added in 2011.

[8] The scenario used for this study was the March 2005 EEA Base Case with a 1.0 Bcfd Broadwater LNG terminal added in November of 2010. EEA does not include Broadwater in its Base Case and it was added to the Base Case in this study as per clients instructions.

On the supply-side, traditional North American gas supplies struggle to keep pace with growing gas demand in the Base Case. Because of declining production in mature producing areas, North America becomes reliant on development of new frontier gas supplies, most notably Arctic gas and LNG imports. In the projection, 1 Bcfd of Mackenzie Delta gas begins flowing in November of 2008. The Alaska pipeline is built in November of 2014 at a capacity of 4 Bcfd. With the addition of Broadwater, LNG imports to the U.S. and Canada rise above 25 Bcfd by 2025 (Figure 7). LNG imports into NEEC rise to 4.3 Bcfd by 2012 and remain constant through 2025 (Figure 8).

> North American natural gas demand will grow led by robust growth in gas use for power generation. Traditional North American gas supplies will struggle to keep pace, prompting an increased reliance on new frontier gas such as LNG.

Figure 7
Total U.S. and Canadian LNG Imports, 2003 – 2025

Source: Energy and Environmental Analysis, Inc.

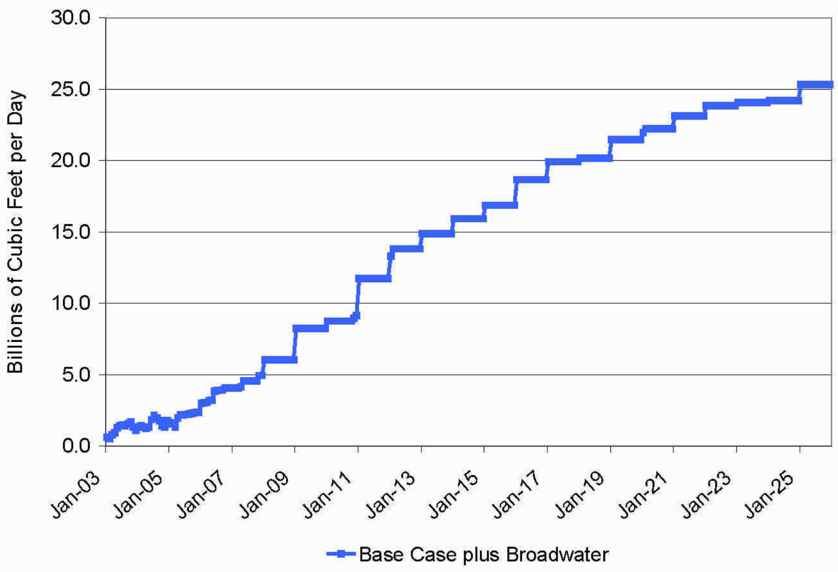

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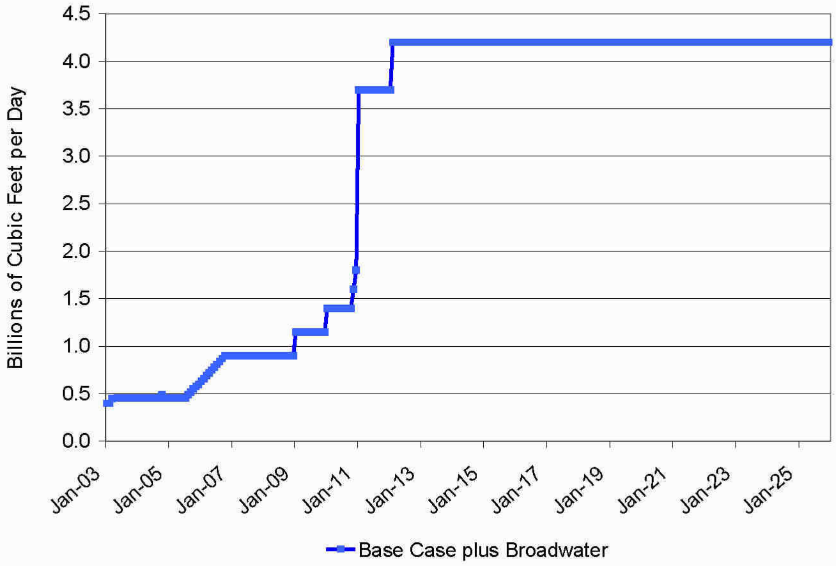
Figure 8
Total NEEC LNG Imports, 2003 – 2025

Source: Energy and Environmental Analysis, Inc.



4.2 Projected Gas Consumption

Case results predict that NEEC gas consumption will rise at about 1.5 percent per year from the recently observed 2004 level of approximately 3,500 Bcf, to over 4,800 Bcf in 2025 (Figure 9), an annual increase of almost 1.3 Tcf or about 36 percent. Growth in total North American gas consumption is 1.7 percent per year over the same time period (Table 7). NEEC gas consumption growth is highest in the earlier part of the forecast, at a rate of 2.8 percent per year from 2004 to 2015. NEEC growth continues until approximately 2020 when annual consumption rises to nearly 5 Tcf before declining back to 4,800 Bcf in 2025. All sectors of the market contribute to gas consumption growth, but the most significant part of the growth occurs in the power sector, which doubles from about 600 Bcf last year to about over 1,200 Bcf in 2025.

NEEC gas consumption is likely to grow fairly significantly over time, creating opportunities for imported LNG. Much of the growth will occur in the power sector.

Figure 9
NEEC Projected Natural Gas Consumption by

Source: Energy and Environmental Analysis, Inc.

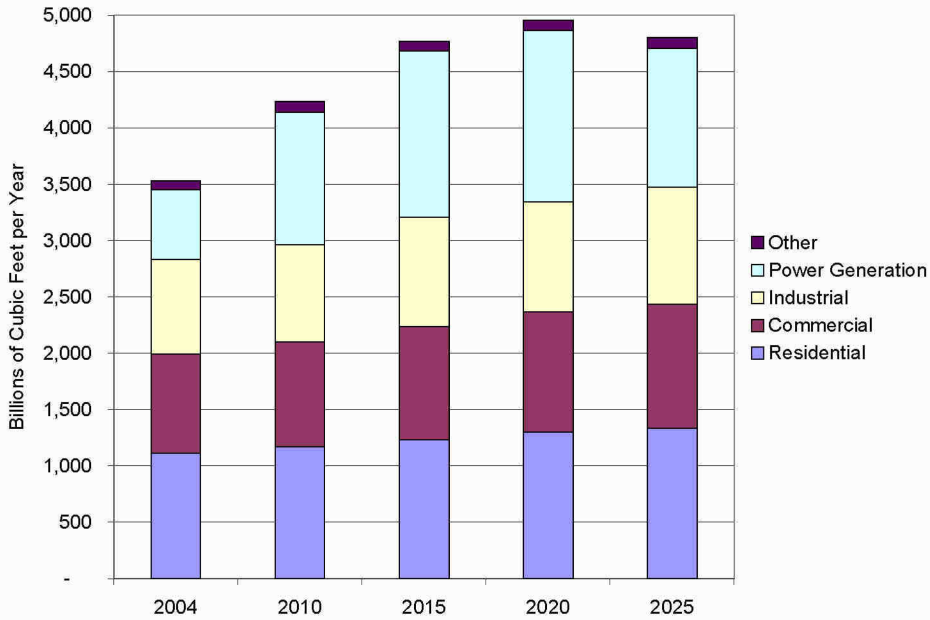


Table 7
NEEC Projected Natural Gas Consumption by Sector in the Base Case (Bcf per Year)

Source: Energy and Environmental Analysis, Inc.

Northeast U.S. and Eastern Canada

Sector	2004	2010	2015	2020	2025	2004-2015 Delta	2004-2015 Annual % Growth	2004-2025 Delta	2004-2025 Annual % Growth
Residential	1,116	1,171	1,236	1,301	1,336	120	0.9%	220	0.9%
Commercial	879	930	1,002	1,065	1,101	124	1.2%	222	1.1%
Industrial	842	863	969	978	1,037	127	1.3%	195	1.0%
Power Generation	619	1,177	1,477	1,521	1,237	858	8.2%	617	3.3%
Other	79	96	88	93	94	9	1.0%	15	0.8%
	3,535	4,237	4,772	4,957	4,804	1,238	2.8%	1,269	1.5%

Total U.S. and Canada

Sector	2004	2010	2015	2020	2025	2004-2015 Delta	2004-2015 Annual % Growth	2004-2025 Delta	2004-2025 Annual % Growth
Residential	5,519	5,966	6,282	6,631	6,796	763	1.2%	1,277	1.0%
Commercial	3,509	3,703	3,925	4,138	4,232	416	1.0%	723	0.9%
Industrial	8,532	8,357	8,596	8,774	9,302	64	0.1%	769	0.4%
Power Generation	4,953	8,091	11,001	12,175	12,419	6,048	7.5%	7,467	4.5%
Other	2,432	2,494	2,599	2,591	2,550	167	0.6%	118	0.2%
Total	24,945	28,611	32,403	34,309	35,299	7,458	2.4%	10,354	1.7%

The residential and commercial sectors will grow very slowly at a combined rate of 1.0 percent per year from 2004 to 2025. This is similar to total North American growth rates in these sectors. By 2025, annual gas consumption in the residential and commercial sectors will rise to over 2,400 Bcf versus just under 2,000 Bcf last year. Projected growth in these sectors is consistent with recent historical trends and is driven by continued population increases that yield continued growth in residential construction and commercial floor space. Growth of housing stock and commercial floor space in the southern portion of NEEC is likely to lag slightly behind the national average as the area is already one of the most densely populated areas and population growth is anticipated to be below the U.S. average. However, natural gas market penetration is expected to increase in New England and Eastern Canada due to recent increases of pipeline capacity into the area. NEEC will tend to experience substantial growth for gas use in distributed generation and combined heat and power applications, some of which may occur in the commercial sector. Further, continued increases in the average square footage of living space per house will also contribute to growth in residential sector gas use. Even so, gas use in these sectors is likely to exhibit relatively slow growth over time compared to growth in the power sector.

Unlike recent trends and consistent with other projected trends throughout North America, the case results show that recent declines in industrial sector gas use in NEEC are unlikely to continue. As has been the case in other regions throughout North America, the most inefficient and marginally economic uses of gas in the industrial sector have already been squeezed out of the market at the relatively high gas prices that have occurred during the past few years. Hence, the projection includes a modest increase in NEEC industrial gas use, consistent with a growing economy, of about 1.0 percent per year over the next twenty years. This rate is similar to the projected overall North American growth rate for this sector.

In contrast to the slow growth of gas use in other sectors, power sector gas use in NEEC is projected to rise fairly quickly at 3.3 percent per year during the next twenty years. However, nearly all of the growth will occur over the next ten years. NEEC gas consumption in the power sector grows at an annual rate of over 8 percent from 2004 to 2015, with consumption reaching nearly 1,500 Bcf by 2015. This occurs as a direct result of increased reliance on gas-fired power capacity to satisfy incremental growth in electricity use over time (Figure 10). NEEC electricity use is projected to grow at 1.4 percent per year for the foreseeable future, slightly below its recent growth rate. Gas-fired generation increases from a little under 100 TWh in 2004 to just under 300 TWh in 2015. Oil generation remains at or below current levels of approximately 29 TWh through 2025. Projected regional oil/gas generation capacity also increases through 2025, albeit at a slower rate than recently observed. A reduced rate of growth in capacity relative to generation has

> NEEC will rely heavily on recently constructed gas-fired capacity to satisfy much of its incremental growth in electric load in the foreseeable future.

the effect of increasing capacity utilization rates of gas/oil units from below 20 percent today to 30 to 35 percent in the longer term.

Beyond 2015, gas-fired generation is projected to face increased competition from clean coal technologies. Currently, the amount of NEEC coal-fired capacity is approximately 32 GW. Although additional coal generation capacity would be attractive at today's relative coal-to-gas fuel prices, permitting and construction takes several years. Therefore, the Base Case projects coal capacity levels to remain stable through 2011. After 2011, coal-fired capacity in the Base Case rises steadily to 50 GW by 2025. Coal capacity utilization remains at approximately 65 percent, the practical limit for the area given electrical load swings and transmission constraints. As coal generation increases along with coal capacity, it could reduce gas consumption in the power sector, even with increasing electricity sales. As a result, the case projects NEEC gas consumption in the power sector in 2020 at just over 1,500 Bcf, and declining to just over 1,200 Bcf in 2025.

Figure 10
Projected NEEC Power Capacity, Generation, and Utilization

Source: Energy and Environmental Analysis, Inc.

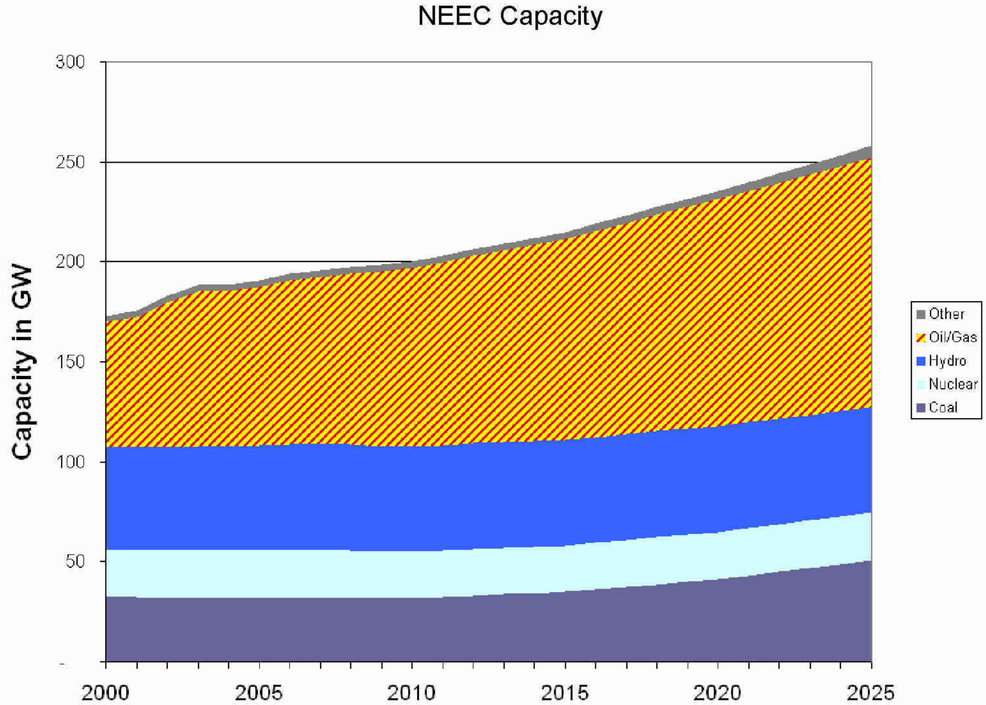
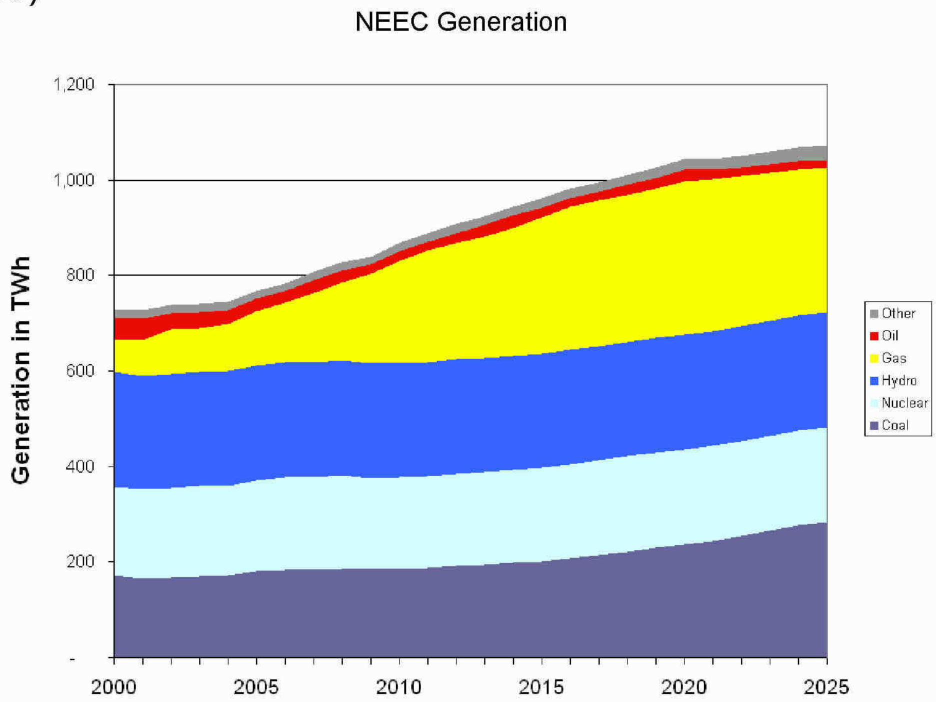
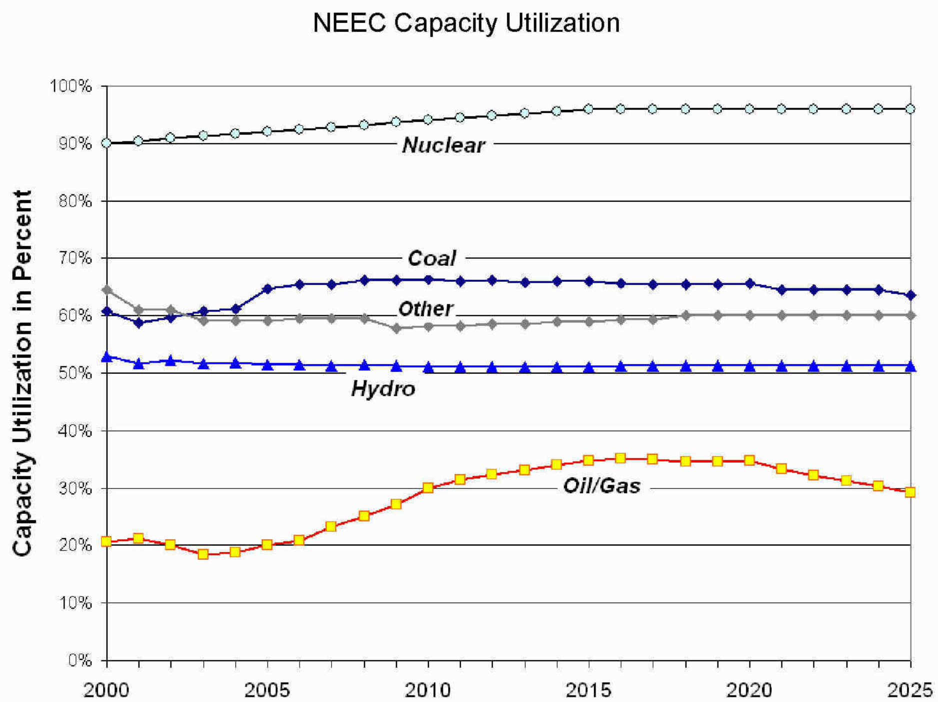


Figure 10
Projected NEEC Power Capacity, Generation, and Utilization (continued)





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4.2.1 Renewable Incentives and Potential Impact on NEEC Gas Consumption

Case projections assume an increase of renewable energy use in NEEC. Power generation from renewable sources, excluding hydro, nearly doubles from 17 TWhs in 2004 to 32 TWhs in 2025, which equates to an annual growth rate of 3 percent. The majority of this increase is due to greater wind generation. Hydro generation is projected to remain constant at 240 TWhs. At these growth rates, renewable sources, including hydro, account for 25 percent of generation in 2025 vs. 35 percent in 2004.

These levels of renewable generation are lower than many of the goals set by states in the Northeast U.S. A higher growth rate of renewable generation would reduce consumption of all fossil fuels. Further, equipment used directly by the consumer, such as solar heating, would reduce electricity consumption. Projected growth in the region's power sector gas consumption from 2004 to 2025 of an additional 617 Bcf per year could be reduced. However, most likely, if an aggressive renewable program is achieved in NEEC, the assumed 18 GW increase in coal generation capacity would most likely not be built. Coal generation projected in the case would be much lower.

To achieve renewable energy use goals, states in the Northeast U.S. have implemented several incentive programs (Table 8). All states except New Hampshire financially encourage the use of renewable fuels to some extent. Typical renewable programs include rebates on qualified equipment purchases, personal and corporate income tax deductions or credits, equipment sales tax exemptions, grants for research and development of renewable energy technology, and loan programs for equipment purchases. Many states have implemented renewable generation targets[9] to be achieved in the states' generation portfolio. To finance these programs, most often a surcharge is placed on electricity sales or nonrenewable generation. The projected funds to be collected from 1998 to 2017 from such surcharges exceed $1 billion.

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[9] Massachusetts and Rhode Island do not include hydro sources.

Table 8
Renewable Incentive Programs by State

Source: North Carolina Solar Center - Database of State Incentives for Renewable Energy

	State								
Renewable Incentives	CT	ME	MA	NH	NJ	NY	PA	RI	VT
Rebate Programs									
Utility						*	*		
State	*	*	*		*	*		*	
State Tax Credits / Deductions									
Personal			*			*			
Corporate			*						
Sales Tax Exemptions			*		*			*	*
Grants for Technologies	*	*	*		*	*	*	*	*
Renewable Portfolio Standards									
Target Percent	10%	30%	4%		6.5%	24%	18%	15%	
By Year	2010	2000	2009		2008	2013	2020	2020	
Loan Programs (State)			*		*	*	*		
Public Benefit Funds									
Projected 1998-2017 ($millions)	$338		$383		$279	$85	$80	$10	

There are similar programs in Canada. For example, the Renewable Energy Deployment Initiative provides direct rebates to industrial consumers installing approved renewable equipment. The Wind Power Production Incentive is a program with a goal to install an additional 1000 megawatts of wind turbines in Canada by 2010. Canada has various programs to encourage solar energy use. The Canadian Government also promotes renewable use directly by buying "green" power directly.

4.3 Projected Natural Gas Prices

The Base Case can be best characterized as a "demand pull" scenario, which is to say that gas demand grows over time, largely a result of growing gas use in power generation, and it pulls gas supply along with it. Because supply in mature producing areas has been heavily exploited, the North American gas market becomes more reliant on new frontier gas supplies, such as imported LNG. The supply/demand balance for natural gas remains tight in this environment, leading to gas prices that are much higher than those observed in the 1990s when the balance was much looser. Generally, gas prices are more consistent with prices observed over the past few years, and less consistent with prices observed in the 1990s.

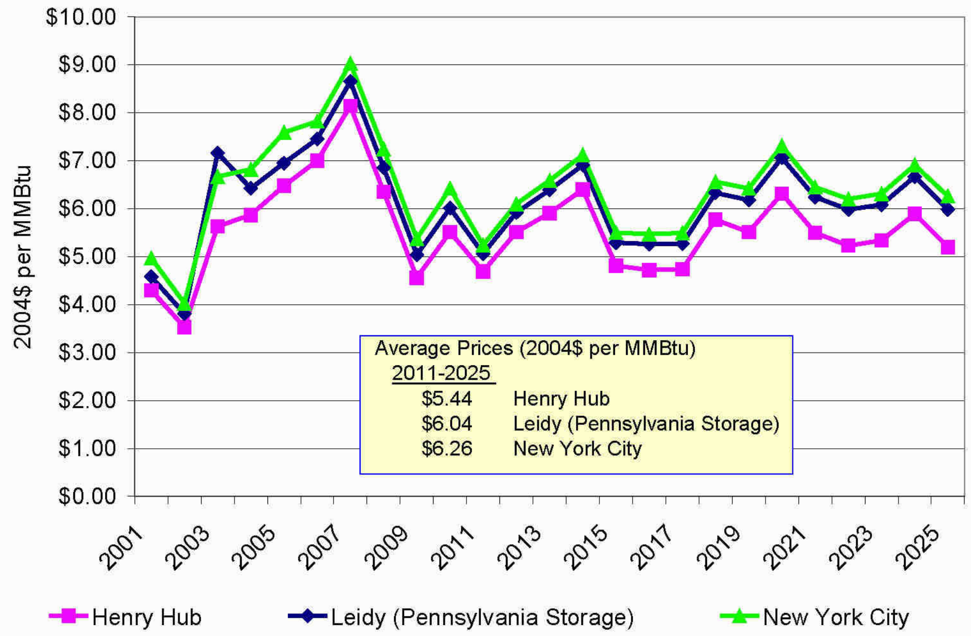
Gas prices are projected to be well above delivered costs of LNG imports, lending support to the resulting import levels.

Projected annual average gas prices

for Henry Hub, Leidy (Western Pennsylvania Storage), and New York City are shown in Figure 11. Henry Hub prices after 2011 range from $4.50 to $7.00 per MMBtu. Assuming that Henry Hub prices are a proxy for North American gas prices in general, this price level amply supports development of all projected “new frontier” supplies, most notably and including LNG imports.

Figure 11
Projected Henry Hub, Leidy, and New York City Natural Gas Prices (2004$ per MMBtu)[10]

Source: Energy and Environmental Analysis, Inc.



There is the potential for significant volatility in gas prices going forward. Although LNG imports are projected to increase at the five[11] LNG import terminals currently operating in North America, Henry Hub prices are still anticipated to continue to rise to over $8.00 per MMBtu by 2007. By 2009, prices are projected to moderate back toward $5.00 per MMBtu as new LNG import terminals along the Gulf Coast begin operation. However, any reduction in gas prices could be delayed or reduced if terminals are delayed or volumes do not reach levels assumed in the forecast.

After the “first wave” of new LNG terminals, Henry Hub prices are projected to steadily increase until the Alaska pipeline project is built near the end of 2014. Henry Hub prices approach $6.50 per MMBtu. The addition of 4 Bcfd of Alaska gas drops average annual prices by over $1.50 per MMBtu. Late 2014 is probably the earliest that the

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[10] Representative of citygate prices, not delivered prices including a distribution margin.

[11] Includes Excelerate’s offshore Energy Bridge facility in which regasification is onboard the tanker.

Alaska pipeline project could be reasonably completed. If the Alaskan project is not built, additional LNG imports will most likely be needed to balance the market. Volatility in natural gas prices after 2015 is highly dependent on the amount of new LNG imports entering the North American market in each year. Further, all of these price projections assume normal weather, and actual weather can swing average annual prices by several dollars per MMBtu above of below the projected prices.

Natural gas in NEEC, as expected, is projected to trade at premiums to prices in supply regions such as the Gulf Coast. Projected annual average gas prices for New York City from 2011 to 2025 range from $5.00 to $7.50 per MMBtu. Projected prices in the Leidy area which are representative of natural gas trades in the main storage area within NEEC are projected to be between Henry Hub and New York prices. The annual average marginal gas prices at Leidy range from $5.00 to $7.00 per MMBtu.[12]

4.5 Projected Sources of Gas Supply for NEEC

NEEC has three major sources of gas supply: pipeline imports, local production, and LNG imports. All supply is locally consumed and there is no transport out of the area. The projected sources of supply to 2025 are shown in Figure 12 and are provided for specific years in Table 9.

Assuming new import facilities are sited, LNG imports will increase in NEEC as other supplies decline. Without incremental LNG imports, gas supply would likely be scarce.

Currently, about 3,600 Bcf of gas supply are delivered into NEEC on an annual basis. Supply requirements are projected to exceed 4,800 Bcf by 2025. A noticeable trend in gas supply is the significant growth of LNG imports in NEEC over time. In 2004, NEEC LNG imports occurred solely at the Everett LNG import facility, and they accounted for merely 5 percent of the region's gas supply. By 2025, case results project that direct LNG imports to NEEC will rise to over 1.5 Tcf per year and account for over 30 percent of the region's gas supply. In addition to the existing Everett terminal, the case assumes a number of additional terminals including Broadwater. These import levels will be achieved only if new terminals are sited within NEEC. Without incremental LNG import capacity, gas supply in the NEEC will likely be scarce.

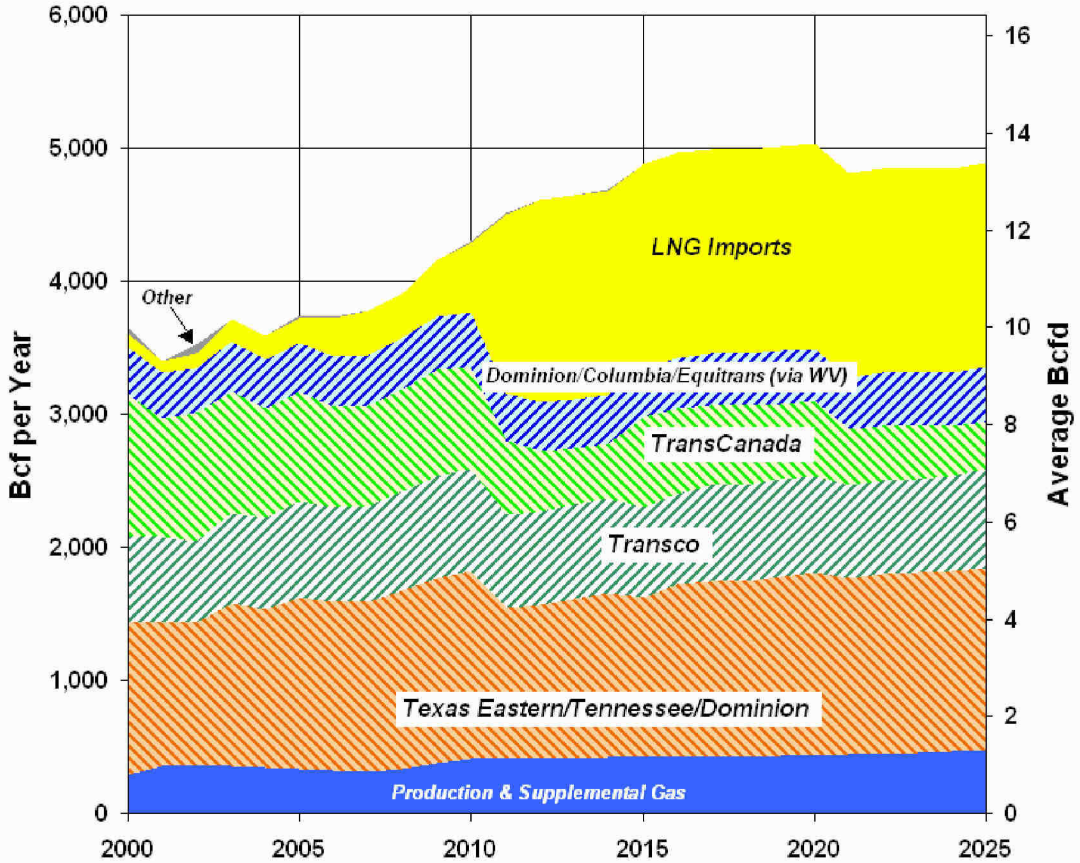
In contrast to the significant increases in LNG imports, many other supplies that currently make their way into NEEC are likely to grow modestly or decline in the foreseeable future. Annual flows from Western Canada into NEEC decline from approximately 825 Bcf in 2004 to about 350 Bcf in 2025. The primary factors behind this trend are declining Western Canadian gas production that makes Western Canadian gas relatively more expensive over time, and a relatively expensive cost for

[12] Representative of citygate prices, not delivered prices including a distribution margin.

transmission from Western Canada to Eastern Canada[13]. Inevitably, Western Canada gas is likely to become more valuable to Canadian consumers and less valuable to U.S. consumers as the U.S. becomes more reliant on imported LNG over time. Hence, exports of Western Canadian gas to the U.S. are likely to decline as gas resource in the Western Canadian Sedimentary Basin is depleted and Western Canadian gas consumers increase their gas use.

Figure 12
Projected Northeast U.S. and Eastern Canada Production and Imports

Source: Energy and Environmental Analysis, Inc.



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[13] In 2003, TransCanada Pipeline, the sole pipeline traversing from Western Canada to Eastern Canada, implemented a price floor on interruptible pipeline capacity equivalent to 110 percent of their firm transmission tariff. The effect of this change has been to increase the marginal cost of transmission from Western Canada to Eastern Canada and the northeast U.S.

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Table 9
NEEC Projected Sources of Supply

Source: Energy and Environmental Analysis, Inc.

	2004	2010	2011	2015	2020	2025
Production	343	406	408	423	434	474
Transco	686	772	698	673	723	740
TransCanada	824	767	549	675	562	356
Dominion/Columbia/Equitrans (from WV)	366	404	356	366	397	407
Texas Eastern/Tennessee/Dominion (from Ohio)	1,194	1,416	1,141	1,203	1,377	1,376
LNG Imports	169	529	1,351	1,533	1,537	1,533
Other (Storage and Balancing Items)	10	4	8	-	1	-
Total	3,594	4,297	4,511	4,872	5,032	4,884

Pipeline imports from Ohio along Texas Eastern, Tennessee, and Dominion currently represent a major source of supply for NEEC. Imports were nearly 1,200 Bcf in 2004 and are projected to rise to 1,375 Bcf by 2025, a 15 percent increase. Supplies along this corridor predominantly come from the Gulf Coast. However, Appalachia production can also reach NEEC through these pipelines. Flows along this corridor will swing in response to LNG imports in NEEC.

Imports from West Virginia into NEEC on Dominion, Columbia, and Equitrans, similar to flows from Ohio, are projected to increase modestly over time. Imports in 2004 were about 370 Bcf and are projected to rise to just over 400 Bcf in 2025, an 11 percent increase. The main source of supply for Columbia Transmission is Columbia Gulf, which transports gas from the Gulf Coast. Dominion and Equitrans transport mainly local Appalachian production.

Likewise, transmission on the Transco pipeline corridor into NEEC is likely to increase only slightly over time. Imports in 2004 were just under 700 Bcf. Transco is currently relied on for long-haul transport of Gulf Coast gas supplies to NEEC. Although some of these supplies may be displaced by LNG imports at Cove Point, Maryland, flows on Transco to the north of the Washington, D.C. area are projected to remain high. However, no new significant expansion of the pipeline is projected[14], and therefore increases along this corridor are limited. After Cove Point's planned expansion in 2008, annual imports on Transco range from 700 to 800 Bcf.

Roughly half of the production in NEEC comes from Offshore Eastern Canada while the remaining half comes from onshore sources in Western Pennsylvania and New York. Total annual production for NEEC was about 340 Bcf in 2004 and is projected to rise steadily to 475 Bcf in 2025. The rate of growth for onshore production will likely depend on market conditions. Offshore Canadian production is projected to be stable at 400

[14] Most industry observers believe that it would be difficult to get the necessary approvals to build additional pipeline under the Potomac River that would be necessary for a significant Transco expansion to NEEC.

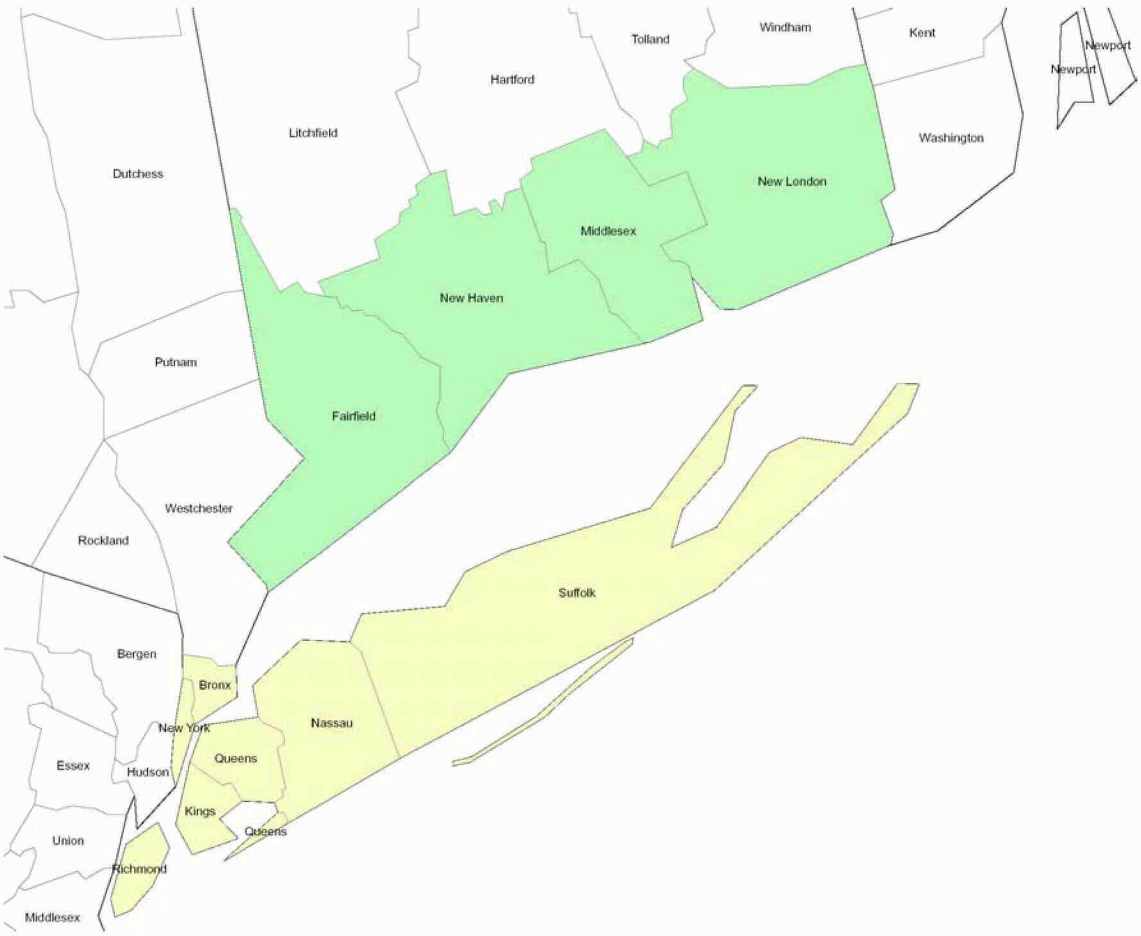
MMcfd after 2010, but could be much higher if there are significant exploration successes. However, producers have recently had difficulty maintaining current production levels.

5
ANALYSIS OF NEW YORK CITY AND SURROUNDING AREAS

This section provides analysis of the natural gas market in New York City, Long Island, and Southern Connecticut, the immediate vicinity for the proposed Broadwater LNG Import Terminal in Long Island Sound (Figure 13). Recent historical demand and major consumers are discussed.

Figure 13
Focus Area

Source: Energy and Environmental Analysis, Inc.



5.1 Gas Consumption in New York City, Long Island, and Southern Connecticut

There is almost 700 Bcf per year of gas consumption in New York City, Long Island, and Southern Connecticut, ample demand to support a significant amount of LNG imports.

The New York City, Long Island, and Southern Connecticut area is one of the most densely populated areas in North America, accounting for about 20 percent of the total end-use gas consumption in the Northeast U.S. and Eastern Canada. Historically, end-use natural gas consumption has been growing in the area by about 2.7 percent per year over the past ten years, rising to nearly 700 Bcf per year by the early part of this decade (Table 10). As in NEEC as a whole, most of the growth in gas consumption in this area has been driven by the power generation sector, where annual consumption has increased by about 100 Bcf over the past decade. There has been modest growth in residential consumption, which has increased by less than 1 percent per year. Commercial gas demand grew in the mid-1990s, but has since been relatively flat at about 120 Bcf per year. Industrial demand accounts for only 6 percent of the area's consumption, and has been declining since the year 2000.

Table 10
Historical Gas Use in New York City, Long Island, and Southern Connecticut (Bcf per year)

Source: Energy and Environmental Analysis Inc. Historic Market Backcast.

	Residential	Commercial	Industrial	Power Generation	Total End-Use
1995	231	89	45	160	525
1996	249	96	45	158	547
1997	233	120	47	174	573
1998	207	117	46	160	531
1999	226	122	48	232	628
2000	241	127	47	241	656
2001	222	121	38	236	617
2002	227	122	39	303	691
2003	256	127	36	257	675
2004	245	123	37	260	664
Annual % Growth	0.6%	3.6%	-2.1%	5.6%	2.7%
% of Total, 2004	37%	18%	6%	39%	100%

5.2 Major Gas Consumers in New York City, Long Island, and Southern Connecticut

5.2.1 Residential and Commercial Gas Consumption

As shown in Table 10 above, approximately 55 percent of gas consumed in the area is in the residential and commercial sectors. There are five major gas utilities, often referred to as local distribution companies (LDCs) that deliver gas to residential and commercial consumers in the area, as shown in Figure 14. The five major utilities are Consolidated Edison, Keyspan New York, Keyspan Long Island, Southern Connecticut Gas, and Yankee Gas Services. Each of the utilities has their own distinct service area. Based on recent gas sales data, three of the five rank among the top 50 gas utilities in the U.S. (see yellow-shaded listings in Table 11). The three utilities – Consolidated Edison, Keyspan New York, and Keyspan Long Island – have a total of 2.7 million customers with total gas sales of almost 290 Bcf per year, accounting for the majority of residential and commercial sales in the area.

The five major utilities rely almost exclusively on pipeline transmission from the Gulf Coast and Western Canada for most (if not all) of their gas supply. All of the provided data on LDC demands suggests that there are significant opportunities to import LNG to gas utilities in the New York City area. Assuming a daily LNG send-out of 1,000 MMcfd, the area's gas utilities could absorb much of that volume of gas.

Figure 14
Gas Utilities (LDC's) in the Northeast U.S. and Eastern Canada

Source: Energy and Environmental Analysis compilation of EIAGIS information.

BANG	Bangor Gas	GAZM	Gasmetro	PECO	PECO Energy Co.
BAYST	Bay State Gas	KS LI	Keyspan Long Island*	PGW	Philadelphia Gas Works
BOST	Boston Gas	KS NY	Keyspan New York*	PPL	PPL Gas Utilities
BERG	Berkshire Gas	NatFuel	National Fuel Gas Distribution Co.	PSE&G	Public Service Electric & Gas
CG PA	Columbia Gas of PA	NEG	New England Gas	RG&E	Rochester Gas & Electric
ConEd	Consolidated Edison	NJ NG	New Jersey Natural Gas	SCTG	Southern Connecticut Gas
CntHud	Central Hudson Gas & Electric Corp	NiMo	Niagara Mohawk	SoJer	South Jersey Gas Co.
ENNG	Energy North Nat Gas*	NSTR	NSTAR Gas	TWP	T.W. Phillips Gas & Oil Co
COLG	Colonial Gas*	NUI	NUI Utilities	UGI	UGI Utilities
CTLP	Connecticut Nat Gas	NUTI	Northern Utilities	VGT	Vermont Gas
Dom P	Dominion Peoples	NYSEG	New York State Electric & Gas Corp.	YANK	Yankee Gas Services
EQT	Equitable Gas	O&RU	Orange & Rockland Utilities		

* A division of Keyspan Energy.

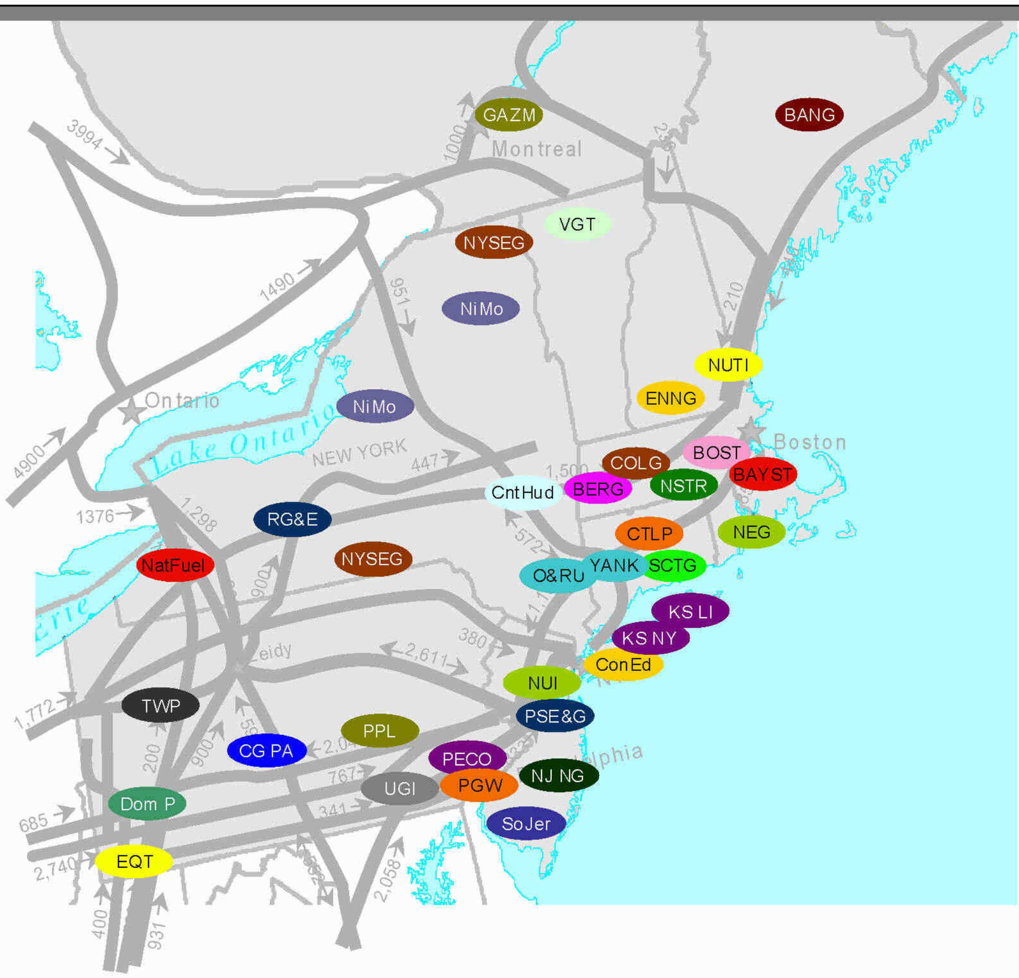


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Table 11
50 Largest Gas Utilities in the U.S. in 2002
Source: AGAeGUS Database

Rank	Company Name	Sales (Bcf) [1]	Revenue (Million US$)	Customers	State
1	SOUTHERN CALIFORNIA GAS CO	356.8	$2,402	5,130,317	CA
2	PACIFIC GAS AND ELEC CO	287.2	$1,886	3,919,928	CA
3	KINDER MORGAN TX PIPELINE	286.2	$959	92	TX
4	NICOR GAS	258.0	$1,474	1,851,444	IL
5	CONSUMERS ENERGY CO	246.0	$1,459	1,649,716	MI
6	PUBLIC SERVICE ELECTRIC GAS CO	243.1	$1,247	1,650,652	NJ
7	HOUSTON PIPELINE CO	194.7	$642	97	TX
8	MICHIGAN CONSOL GAS CO	169.5	$1,139	1,130,429	MI
9	CENTERPOINT ENERGY ENTEX	152.3	$1,064	1,550,747	TX
10	CENTERPOINT ENERGY MINNEGASCO	143.8	$826	719,307	MN
11	TXU GAS COMPANY	143.7	$876	1,450,164	TX
12	COLUMBIA GAS DIST CO [2]	141.8	$1,161	1,342,975	
13	PUB SERVICE CO OF COLORADO	139.3	$703	1,143,142	CO
14	KEYSPAN ENERGY DEL CO (KEYSPAN NY)	136.2	$1,212	1,159,424	NY
15	KINDER MORGAN TEJAS PIPELINE	125.4	$479	38	TX
16	PEOPLES GAS LIGHT AND COKE COMPANY	116.4	$882	817,296	IL
17	SOUTHWEST GAS CORP	115.9	$1,038	1,169,523	AZ
18	NORTHERN INDIANA PUBLIC SERVICE CO	99.4	$694	674,929	IN
19	NORTHERN STATES PWR CO [3]	98.4	$582	522,152	MN
20	QUESTAR GAS CO	95.1	$565	734,089	UT
21	KINDER MORGAN SHIP CHANNEL	92.7	$324	22	TX
22	CONSOLIDATED EDISON NEW YORK INC	86.8	$902	1,051,400	NY
23	OKLAHOMA NATURAL GAS CO	82.0	$611	778,105	OK
24	EAST OHIO GAS COMPANY DOMINION EAST	80.6	$549	629,856	OH
25	PUGET SOUND ENERGY	79.5	$673	613,420	WA
26	LACLEDE GAS COMPANY	79.4	$572	637,654	MO
27	MIDAMERICAN ENERGY CO	78.7	$518	654,111	IA
28	WASHINGTON GAS LT CO	78.4	$752	735,208	VA
29	CROSSTEX ENERGY SERVICES	77.7	$236	44	TX
30	WISCONSIN GAS COMPANY	74.9	$503	555,627	WI
31	NORTHWEST NATURAL GAS CO	67.0	$619	548,842	OR
32	KEYSPAN ENERGY DEL LONG ISLAND	64.7	$678	461,709	NY
33	CENTANA INTRASTATE PIPELINE CO	64.4	$231	12	TX
34	INDIANA GAS COMPANY INC	64.3	$504	531,991	IN
35	KANSAS GAS SERVICE COMPANY	62.9	$448	632,273	KS
36	NIAGARA MOHAWK POWER CORP	60.7	$512	493,360	NY
37	PHILADELPHIA GAS WORKS	59.5	$593	520,891	PA
38	BOSTON GAS CO D B A KEY SPAN ENERGY	59.4	$569	549,484	MA
39	CENTERPOINT ENERGY ARKLA	59.3	$499	561,198	AR
40	NATIONAL FUEL GAS DIST NY	58.8	$463	466,294	NY
41	UNIT GAS TRANS CO	54.9	$182	104	TX
42	PECO ENERGY COMPANY	54.8	$490	448,501	PA
43	WISCONSIN ELEC PWR CO	54.4	$380	416,049	WI
44	ILLINOIS POWER COMPANY	54.0	$367	399,182	IL
45	MISSOURI GAS ENERGY	53.9	$442	490,002	MO
46	SAN ANTONIO PUB SVC BD	52.1	$252	306,430	TX
47	SAN DIEGO GAS AND ELECTRIC CO	50.3	$344	781,799	CA
48	NEW JERSEY NATURAL GAS	49.9	$473	412,766	NJ
49	PNM	49.4	$356	442,466	NM
50	CINCINNATI GAS & ELEC CO	46.5	$338	380,651	OH
	Total of Top 50 Companies	5,500.8	$35,672	41,115,912	
	Total of NYC/Long Island Companies	287.7	2,791.5	2,672,533	
	NYC/Long Island Percent of Total in Top 50	5.2%	7.8%	6.5%	

1. Sales to all customers, including sales to industrial facilities and power providers.
2. Includes all of the Columbia Gas distribution companies in the area, i.e., Columbia Gas of Ohio Columbia Gas of Virginia, Columbia Gas of Pennsylvania, and Columbia Gas of Maryland.
3. Part of Xcel Energy.

5.2.2 Industrial Gas Consumption

As mentioned above, industrial gas consumption accounts for a relatively small portion of the area's total gas consumption, or only 6 percent of total consumption in 2004. There are several hundred industrial facilities in the area that collectively consume about 40 Bcf per year of gas. The majority of industrial gas consumption occurs at facilities consuming very small quantities of gas each year. The largest industrial consumers (defined here as those facilities with consumption greater than 0.2 MMcfd) are shown in Figure 15 and listed in Table 12. These large industrial consumers account for about 40 percent of the total industrial gas consumption in the area.

Chemical manufacturing (which includes pharmaceuticals and industrial chemicals) is the largest gas consuming industry in the area, representing about one-third of the total consumption in the sample. The rest of the industrial consumption is fairly diverse, with no one industry representing more than 20 percent of the total.

Figure 15
Largest Industrial Gas Consumers in New York City, Long Island, and Southern Connecticut

Source: EEA representation of data from IHS Major Industrial Production Database (MIPD).

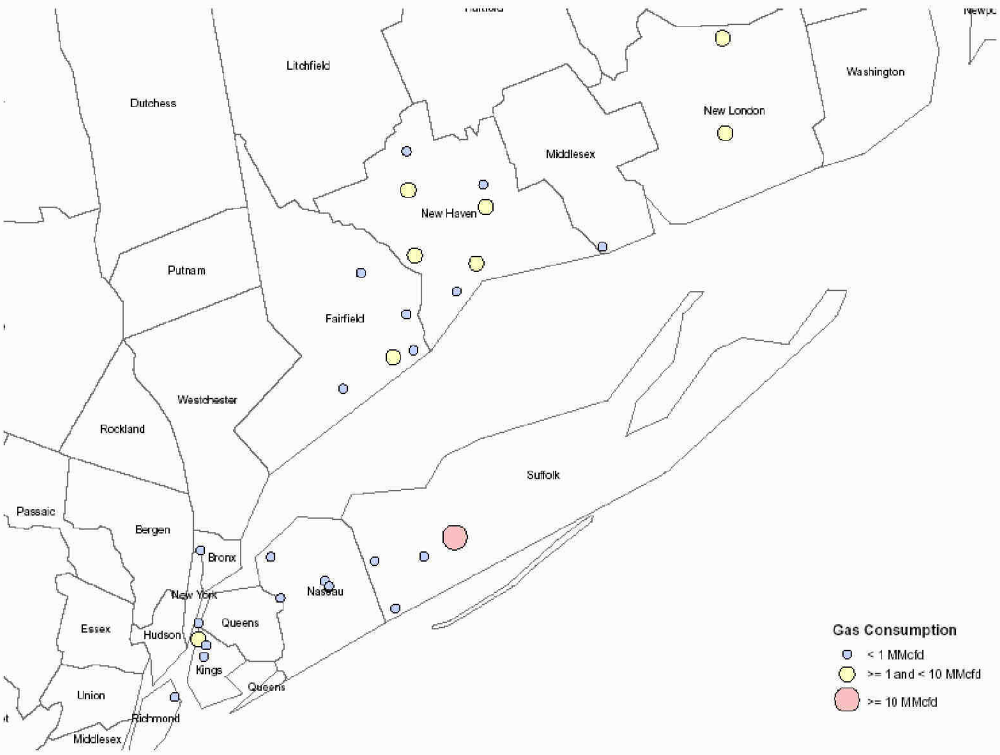

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Table 12
Largest Industrial Gas Consumers in New York City, Long Island, and Southern Connecticut
Source: IHS Major Industrial Production Database (MIPD).

State	County	Plant Name	Industry	MMcf / Day	Bcf / Year
New York City					
NY	Rockland	WEYTH LABORATORIES INC	Medicinals & Botanicals	8.2	3.00
NY	Kings	DOMINO SUGAR CORP	Cane Sugar Refining	5.0	1.82
NY	Rockland	UNITED STATES GYPSUM CO INC	Gypsum Products	2.9	1.04
NY	Rockland	NICE-PAK PRODUCTS INC	Paper Mills	0.5	0.20
NY	Rockland	NOVARTIS PHARMACEUTICALS CORP	Pharmaceutical Preparations	0.5	0.18
NY	Kings	PFIZER INC	Pharmaceutical Preparations	0.4	0.15
NY	Richmond	SUN CHEMICAL CORP	Industrial Organic Chemicals, Nec	0.4	0.13
NY	Kings	WITCO CORPORATION	Industrial Organic Chemicals, Nec	0.3	0.12
NY	Bronx	STELLA DORO BISCUIT CO INC	Cookies & Crackers	0.2	0.08
NY	Queens	PEPSI-COLA BOTTLING CO OF NY	Bottled & Canned Soft Drinks	0.2	0.07
Total New York City				18.6	6.78
Long Island New York					
NY	Suffolk	ESTEE LAUNDER	Cosmetics & Toilet Preparations	0.8	0.30
NY	Suffolk	GEORGE WESTON BAKERIES INC	Bread & Other Bakery Products	0.6	0.23
NY	Nassau	SPECTRONICS CORP	Industrial Organic Chemicals, Nec	0.6	0.21
NY	Nassau	TISHCON CORP	Pharmaceutical Preparations	0.5	0.20
NY	Nassau	UNISYS CORP	Search & Navigation Equipment	0.3	0.11
NY	Nassau	E-Z-EM DELAWARE CORP	Diagnostic Substances	0.3	0.11
NY	Suffolk	RUSSELL PLASTICS TECHNOLOGY	Plastic Materials & Resins	0.3	0.09
NY	Nassau	THOMSON INDUSTRIES INC	Ball & Roller Bearings	0.2	0.08
Total Long Island New York				3.6	1.32
Southern Connecticut					
CT	New Haven	ANSONIA COPPER & BRASS INC	Rolling & Drawing of Copper	5.1	1.88
CT	New London	CARAUSTAR INDUSTRIES INC	Paperboard Mills	4.4	1.60
CT	New Haven	SIMKINS INDUSTRIES INC	Paperboard Mills	2.0	0.72
CT	Fairfield	BRIDGEPORT METAL GOODS MFG CO	Plastics Products, Nec	1.5	0.56
CT	New Haven	PRATT & WHITNEY	Aircraft Engines & Engine Parts	1.5	0.54
CT	New London	SMURFIT STONE CONTAINER CORP	Paperboard Mills	1.2	0.43
CT	New Haven	UNIROYAL CHEMICAL CO	Industrial Organic Chemicals, Nec	1.1	0.40
CT	New Haven	BAYER CORP	Pharmaceutical Preparations	0.8	0.31
CT	New Haven	EYELET DESIGN INC	Metal Stampings, Nec	0.5	0.20
CT	New Haven	ALLEGHENY LUDLUM CORP	Cold Finishing of Steel Shapes	0.5	0.18
CT	Middlesex	STANLEY-BOSTITCH INC	Misc. Fabricated Wire Products	0.4	0.13
CT	Fairfield	UNITED TECHNOLOGIES CORP	Aircraft	0.3	0.12
CT	Fairfield	EXXON MOBIL	Plastic Materials & Resins	0.3	0.10
CT	Fairfield	PEPPERIDGE FARM INC	Bread & Other Bakery Products	0.3	0.10
CT	Fairfield	AMERICAN HEAT TREATING INC	Metal Heat Treating	0.2	0.07
Total Southern Connecticut				20.0	7.32

Industry	MMcf / Day	Bcf / Year
CHEMICALS	14.5	5.28
PAPER & ALLIED PRODUCTS	8.1	2.95
FOOD & KINDRED PRODUCTS	6.3	2.29
PRIMARY METALS	5.8	2.12
STONE CLAY & GLASS	2.9	1.04
TRANSPORTATION EQUIPMENT	1.8	0.66
RUBBER & MISC. PLASTICS	1.5	0.56
FABRICATED METALS	0.9	0.33
INSTRUMENTS	0.3	0.11
NON-ELECTRIC MACHINERY	0.2	0.08
Total	42.3	15.42

5.2.3 Power Generation Gas Consumption

There are about 75 power plants in the area that use natural gas as either a primary or secondary fuel. Figure 16 and Table 13 show the 45 largest gas-fired power plants in the region, based on estimated fuel consumption in the year 2003. These 45 plants represent over 90 percent of gas consumed for power generation in the area. The remaining 30 plants either use gas as a secondary fuel or operate very few hours per year, so their annual gas use is miniscule.

> Almost 50 different power plants collectively consume about 600 MMcfd of gas in the New York City, Long Island, and Southern Connecticut area.

Twenty-three of the area's largest gas-fired plants are located within New York City, which is the area's primary electric load center. The plants in New York City represent about two-thirds of the area's total gas-fired capacity and over half of the power generation gas consumption.

Power plants that use gas as a primary or secondary fuel are critical to the area's electric generation supply. In the New York City metropolitan area, gas-fired plants make up nearly 90 percent of the total generating capacity. Since the area is so dependent on gas-fired generation, the addition of a new LNG import facility would increase the reliability of both the area's electric and gas supply. The topic of reliability is addressed in greater detail below.

Figure 16
Largest Gas-Fired Power Plants in New York City, Long Island, and Southern Connecticut
Source: EEA representation of data from EIA and Platts Power Plant Databases.

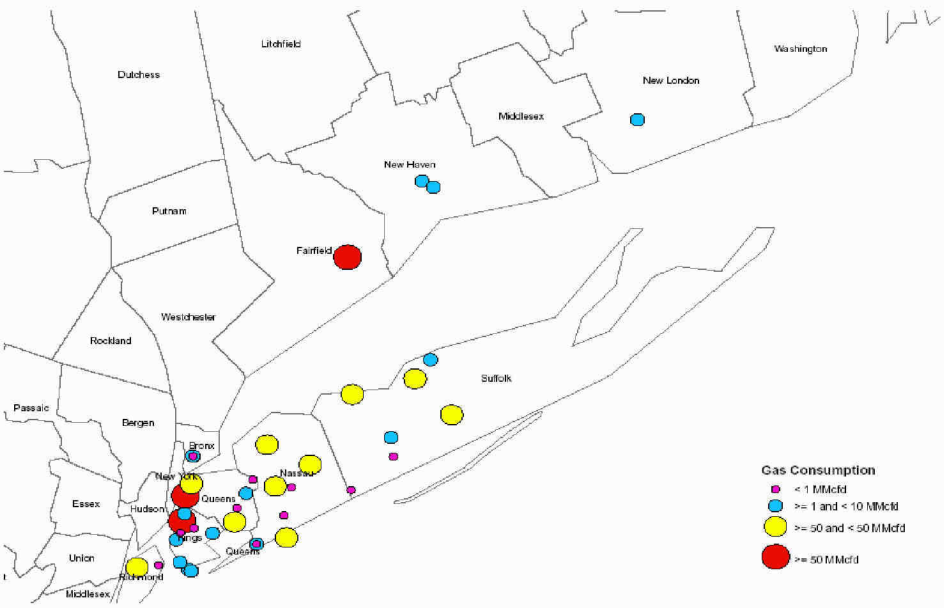

Table 13
Largest Gas-Fired Power Plants in New York City, Long Island, and Southern Connecticut

Source: EEA representation of data from EIA and Platts Power Plant Databases; estimated consumption for 2003.

State	County	Plant Name	Capacity (MW)	MMcf / Day	Bcf / Year
New York City					
NY	Queens	Ravenswood	3,654	115.8	42.28
NY	Kings	Brooklyn Navy Yard Cogeneration	322	52.4	19.14
NY	Queens	Astoria Generating Station	360	59.7	21.81
NY	Richmond	Arthur Kill Generating Station	1,863	30.4	11.11
NY	Queens	Kennedy International Airport Cogen	121	18.3	6.69
NY	Queens	Far Rockaway	100	11.5	4.20
NY	Kings	Narrows Gas Turbines Generating	704	9.3	3.40
NY	Bronx	Hell Gate	94	8.5	3.09
NY	Bronx	Harlem River Yard	94	5.9	2.16
NY	Kings	Warbasse Cogen Facility	35	5.0	1.82
NY	Queens	Vernon Boulevard	94	3.8	1.38
NY	Kings	23rd & 3rd	94	3.5	1.28
NY	Kings	The American Sugar Refining Co Brooklyn	10	1.5	0.55
NY	Kings	North 1st	47	3.1	1.14
NY	Kings	Gowanus Gas Turbines Generating	704	2.8	1.01
NY	Kings	Starrett City Cogen Facility	12	1.6	0.57
NY	Richmond	Pouch	47	1.3	0.48
NY	Queens	Bayswater Peaking Facility LLC	58	1.1	0.40
NY	Bronx	Bronx Zoo	3	0.4	0.14
NY	Queens	North Shore Towers	9	0.7	0.24
NY	Queens	Honeywell Farms	2	0.4	0.15
NY	Kings	St Marys Hospital	1	0.2	0.05
NY	Kings	New York Methodist Hospital	2	0.2	0.09
Total New York City			8,430	337.5	123.18
Long Island New York					
NY	Nassau	E F Barrett	687	61.5	22.44
NY	Suffolk	Northport	774	32.1	11.70
NY	Suffolk	Richard M Flynn	164	29.1	10.63
NY	Nassau	Glenwood	334	25.2	9.21
NY	Nassau	Bethpage Power Plant	144	17.3	6.31
NY	Nassau	Trigen Nassau Energy	55	9.3	3.40
NY	Suffolk	Stony Brook Cogen Plant	47	8.7	3.17
NY	Suffolk	Port Jefferson	294	8.6	3.15
NY	Suffolk	PPL Edgewood Energy LLC	100	4.3	1.57
NY	Suffolk	Brentwood	47	2.2	0.79
NY	Suffolk	Entenmanns Energy Center	4	0.6	0.23
NY	Nassau	Hofstra University	2	0.4	0.14
NY	Nassau	Charles P Keller	29	0.3	0.11
NY	Suffolk	South Oaks Hospital	1	0.2	0.08
Total Long Island New York			2,682	199.8	72.94
Southern Connecticut					
CT	Fairfield	Bridgeport Energy Project	520	84.2	30.73
CT	New London	Pfizer Groton Plant	33	5.4	1.96
CT	New London	Sprague Paperboard	20	3.5	1.29
CT	New Haven	PPL Wallingford Energy LLC	250	3.9	1.44
CT	New Haven	Devon Station	344	2.4	0.88
Total Southern Connecticut			1,167	99.4	36.30
Total for NYC/Long Island/Southern Connecticut			12,278	636.75	232.41

6 THE BROADWATER FACILITY AND INCREASING RELIABILITY

This section discusses the impact of LNG on gas and electric power reliability, with a focus on New York City, Long Island, and Connecticut consumers.

6.1 Impact of LNG on Gas and Power Reliability

There is a close relationship between the reliability of natural gas and electricity supplies in the Northeast U.S. and Eastern Canada. The interdependency between the two systems stems from recent increases in gas-fired capacity, both in absolute terms and as a percentage of the region's total capacity. For the region as a whole, approximately 20,000 MW of new gas-fired capacity has been added since 1998. While the majority of the new gas-fired units have been added in the New England states, natural gas is also a leading fuel for electric generation in New York. Currently, gas-fired units represent over 40 percent of New England's generating capacity, and about 25 percent of the capacity in New York. Within the New York City metropolitan area, about 90 percent of the generating capacity uses natural gas a primary or secondary fuel.

> At peak send-out, Broadwater would supply enough gas to fuel 5,800 MW of gas-fired capacity, which equates to 50 percent of the gas-fired capacity in New York City, Long Island, and Southern Connecticut.

While there are some similarities between gas pipeline planning and operations and electrical transmission system planning and operations, there are also significant differences. These differences arise, in part, because the electrical transmission system owner has very little control over the size or location of the electrical loads served by the transmission system, or in the timing of the use of electricity by the ultimate customer. A pipeline, on the other hand, knows the location of the customers who have a firm right to transportation capacity. In addition, the pipeline knows the availability of alternative receipt and delivery point rights consistent with the pipeline's tariff, and has contracts in place that describe how much firm transportation capacity each customer may utilize.

In general, the owners of the electrical systems (the ISO and the RTO along with the LSE) anticipate load growth, and plan, design, and construct a transmission system that meets specific reliability standards and that is capable of serving forecast customer demands. The nature of the electrical grid, with numerous nodes where facilities are interconnected, and multiple parallel paths for electricity flow, results in a flexible, robust electrical delivery system. Capability may exist to accommodate growth in demand or to provide service to customer demands from alternative generation sources.

By contrast, pipelines do not build facilities based on projected load growth. The U.S. Federal Energy Regulatory Commission (FERC) policy granting a pipeline the certificate needed prior to construction places great weight on binding commitments between the pipeline shippers and the pipeline to demonstrate the need for new pipeline capacity. In most cases where a significant expansion is proposed, the costs of the expansion are borne by the incremental shippers underpinning the expansion with no cost responsibility for the new capacity borne by the existing customer base for at least ten years. Thus, additional customers request firm service from a pipeline that then adds new facilities or improves existing facilities, resulting in new pipeline capacity closely matching requirements of the new customers. If all of the pipeline's firm customers use their full capability, little or no excess pipeline capacity will be available[15].

The interconnected electric transmission systems are designed and operated in a way to prevent the sudden loss of any single circuit, transformer or generating unit causing a disruption to firm customer demand. Since electric supply losses can occur quickly and be very large in magnitude, reliability standards require that each operating region's electrical system be designed to handle such contingencies. For example, the amount of spinning reserves within a region has to be great enough to reliably accommodate the loss of output from a local power plant or a sudden reduction of electricity imports (e.g., due to the loss of a transmission line). However, there are no similar reliability standards for natural gas pipelines. Although interconnections exist among the natural gas pipelines, the pipelines generally operate independently of one another. This means all consumers who are supplied by a single pipeline are at risk in the event of a system failure on that pipeline. Also, the pipeline owners are under no legal obligation to assist one another in emergency situations, unless a contractual arrangement to do so has been previously negotiated[16].

Throughout the Northeast U.S. and Eastern Canada, the single most critical contingency for the electric systems is not the loss of a power plant or a transmission line, but rather an outage on a natural gas pipeline or even a single, critically-positioned compressor station. The interruption of supply on a single gas pipeline may result in the loss of multiple electric generators. Although some natural gas-fired electric generators have the capability to use oil as a backup fuel, there are a number of factors that limit this capability to mitigate a widespread loss of natural gas deliveries. As newer combined cycle and combustion turbine generators have replaced older oil/gas steam turbine generators, there has been a significant decrease in alternate fuel capability. Even if a generator has alternate fuel capability, it must be taken off line to switch out

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[15] This is not always true. For example, where productive capacity supporting flows into production area pipelines has declined, pipelines have been de-contracted and have been running at fairly low load factors.

[16] While there is no regulatory requirement for cooperation in emergency situations, pipeline owners have cooperated in the past and could reasonably be expected to do so in the future.

burners, so it cannot respond instantaneously to a loss of gas supply. Also, generators with alternate fuel capability may not have oil supplies available when an emergency occurs if they have used their oil stocks earlier in the season. Still others may not be able to switch when called upon due to environmental limitations. Finally, most generators with oil fuel backup do not have enough on-site oil in storage to ride through a very long interruption of gas supplies. As a result of these and other factors, there is an electric reliability concern that a single gas pipeline outage may result in a loss of generation in excess of the allowable limits based solely on standard electric system planning.

Pipeline outages are not the only reliability concern. Cold weather poses challenges to both the electrical and gas systems, since extreme weather causes spikes in both gas and electricity demand. In both of the last two winters, the New York ISO and ISO-New England operators encountered an increased number of generator outages due to lack of fuel. In New York, generators were unable to meet their Day Ahead commitments for over 800 unit-hours in 2003 due to unavailable fuel. About half of those unit-hours' outages affected New York City units, and nearly all of the units affected were nominally dual-fuel units. During the winter of 2002-03, ISO-New England reported that it's generating sector experienced approximately 3,000 Equivalent Outage Hours (EOH) reported as "gas-related issues." This involved 29 different units that have a total winter capacity of 6,875 MW.

The gas supply constraints that emerged in 2003 and 2004 confirm the earlier findings of studies conduced by ISO-New England[17,18]. Those studies found that despite the pipeline enhancements into and within New England, the new facilities do not materially mitigate the size of the expected gas transportation shortfall to the electric generation sector during the winter peak. The studies also indicated that on extremely cold winter days when there is insufficient pipeline capacity to satisfy coincident demands of both LDC customers (primarily residential and commercial gas consumers) and gas-fired generators, the impact would be borne predominately by those gas-fired merchant generators whose gas transportation arrangements are not firm from the wellhead or storage centers to the burnertip. In its review of natural gas supply, pipeline capacity, and LNG imports, ISO-New England found that natural gas is critical to generation year-round. In addition to New York City, the Boston area is also heavily dependent on gas, with 1,700 MW of baseload gas-fired capacity. The report indicated that as much as 3,900 MW of gas-fired generation could be unserved by pipelines during a peak winter day.

The New York State Energy Research and Development Authority and the New York ISO sponsored a similar study in 2002 to address concerns about the adequacy of the New York gas delivery infrastructure for simultaneously meeting traditional gas

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[17] Steady-State (Phase I) and Transient (Phase II) Analysis of New England's Interstate Pipeline Delivery Capability 2001-2005, ISO New England, February 2003.

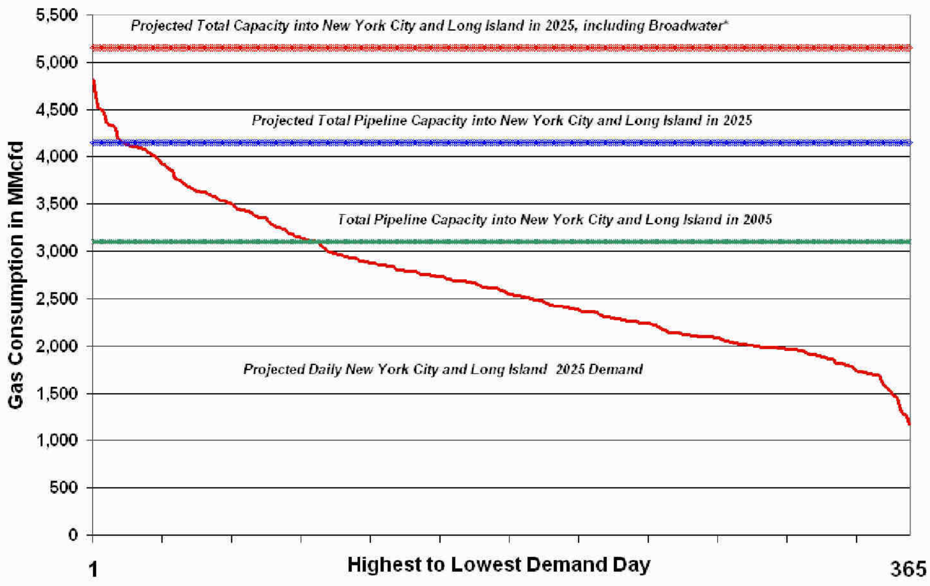
[18] Natural Gas and Fuel Diversity Concerns in New England and the Boston Metropolitan Load Pocket, ISO New England, July 1, 2003.

demands and future gas demand for electric generation[19]. The analysis indicated that the amount of new gas supply (in the form of pipeline capacity or LNG imports) that will be needed for electric generation depends on the amount of gas-fired generating capacity that is actually built and the extent to which the ability to burn oil is maintained. Since that study was prepared in 2002, over 1,100 MW of additional gas-fired capacity has come online in New York. Very little, if any, of the new capacity has backup fuel capability. Over the same time period, there have been only a few, relatively small gas pipeline capacity expansions within the region.

The Broadwater LNG import facility would increase the reliability of both the gas and electric systems by adding a significant amount of gas supply and delivery capability to the region as a whole, and to the New York City area in particular. As mentioned earlier for NEEC as a whole, over 15 Bcfd of gas pipeline capacity enters the region. The addition of a new LNG facility with a peak send-out capability of 1,000 MMcfd would increase the region's gas supply by over 5 percent. For the New York City area, the impact of Broadwater is even more significant (Figure 17). Pipeline capacity to the area based on firm contracts is 3.2 Bcfd. By 2025, a minimum of 1 Bcfd of additional pipeline capacity is projected to be needed. The addition of the Broadwater facility would increase the peak delivery capability by about 25 percent[20].

Figure 17
Buffer Created by Broadwater Supplies on Pipeline Utilization During Peak Periods

Source: Energy and Environmental Analysis, Inc.



* This is the upper boundary on total capacity, assuming the full 1,000 MMCfd of peak supply capability from Broadwater is available to New York City and Long Island.

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19 The Ability to Meet Future Gas Demand from Electricity Generation in New York State, New York State Energy Research and Development Authority and New York ISO, July 2002.

20 Assumes that all of Broadwater's supply would be incremental to other supplies.

In terms of electrical generation, at peak send-out Broadwater would supply enough gas to fuel 5,800 MW of gas-fired capacity, assuming an average heat rate of 7,400 Btu/kWh. This equates to over 7 percent of the current gas-fired capacity in NEEC and about 50 percent of the gas-fired capacity in New York City, Long Island, and Southern Connecticut.

In addition to increasing the region's supply of natural gas, a new LNG facility would also provide greater supply diversity. Local gas production supplies less that 10 percent of the region's consumption and LNG imports at the Everett facility currently contribute about 5 percent of supply. The remaining 85 percent of region's gas supply is delivered via long-haul pipelines, primarily from the Gulf Coast and Western Canada. In particular, the region is heavily dependant on two pipelines, Transco and TransCanada[21], which together deliver about 40 percent of the region's gas supply. A new LNG import facility would increase the percentage of the region's supply coming from LNG, and provide a backup to the interstate pipelines, creating gas and electric system reliability, particularly in winter months when the gas delivery system can be stressed.

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[21] Provides gas deliveries to Iroquois Pipeline, PNGTS, and various other pipelines through Niagara interconnects.

7
EEA'S GAS MARKET DATA AND FORECASTING SYSTEM

EEA's Gas Market Data and Forecasting System (GMDFS), a nationally recognized modeling and market analysis system for the North American gas market will be used to obtain the scenario results for this project. EEA's GMDFS was developed in the mid-1990s to provide forecasts of the North American natural gas market under different assumptions. In its infancy, the model was used to simulate changes in the gas market that occur when major new sources of gas supply are delivered into the marketplace. For example, much of the initial work with the model in 1996-97 focused on measuring the impact of the Alliance pipeline completed in 2000. The questions answered in the initial studies include:

- What is the price impact of gas deliveries on Alliance at Chicago?
- What is the price impact of increased takeaway pipeline capacity in Alberta?
- Does the gas market support Alliance? If not, when will it support Alliance?
- Will supply be adequate to fill Alliance? If not, when will supply be adequate?
- What is the marginal value of gas transmission on Alliance?
- What is the impact of Alliance on other transmission and storage assets?
- How does Alliance affect gas supply (both Canadian and U.S. supply)?
- What pipe is required downstream of Alliance to take away "excess" gas?

Subsequently, EEA's model has been used to complete strategic planning studies for many private sector companies. The different studies include:

- Analyses of different pipeline expansions
- Measuring the impact of gas-fired power generation growth
- Assessing the impact of low and high gas supply
- Assessing the impact of different regulatory environments

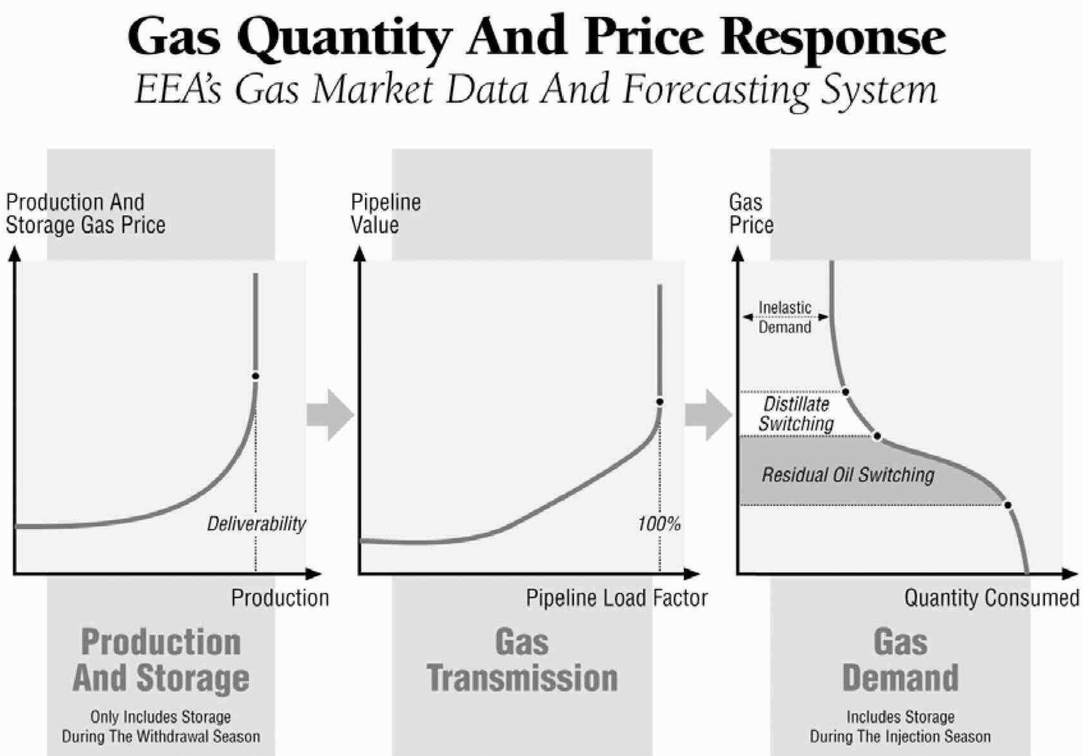
In addition to its use for strategic planning studies, the EEA model has been widely used by a number of institutional clients and advisory councils, including INGAA, who relied on the model for the 30 Tcf market analysis completed in 1998 and again in 2004. GRI has relied on the EEA model for the GRI Baseline Projection. The model was also the primary tool used to complete the widely referenced studies on the North American Gas Market for the National Petroleum Council in 1999 and 2003.

EEA's Gas Market Data and Forecasting System is a full supply/demand equilibrium model of the North American gas market. The model solves for monthly natural gas prices throughout North America, given different supply/demand conditions, the assumptions for which are specified by the user.

Overall, the model solves for monthly market clearing prices by considering the interaction between supply and demand curves at each of the model's nodes. On the supply-side of the equation, prices are determined by production and storage price curves that reflect prices as a function of production and storage utilization (Figure 18). Prices are also influenced by "pipeline discount" curves, which reflect the change in basis or the marginal value of gas transmission as a function of load factor. On the demand-side of the equation, prices are represented by a curve that captures the fuel-switching behavior of end-users at different price levels. The model balances supply and demand at all nodes in the model at the market clearing prices determined by the shape of the supply and curves. Unlike other commercially available models for the gas industry, EEA does significant backcasting (calibration) of the model's curves and relationships on a monthly basis to make sure that the model reliably reflects historical gas market behavior, instilling confidence in the projected results.

Figure 18
Supply/Demand Curves

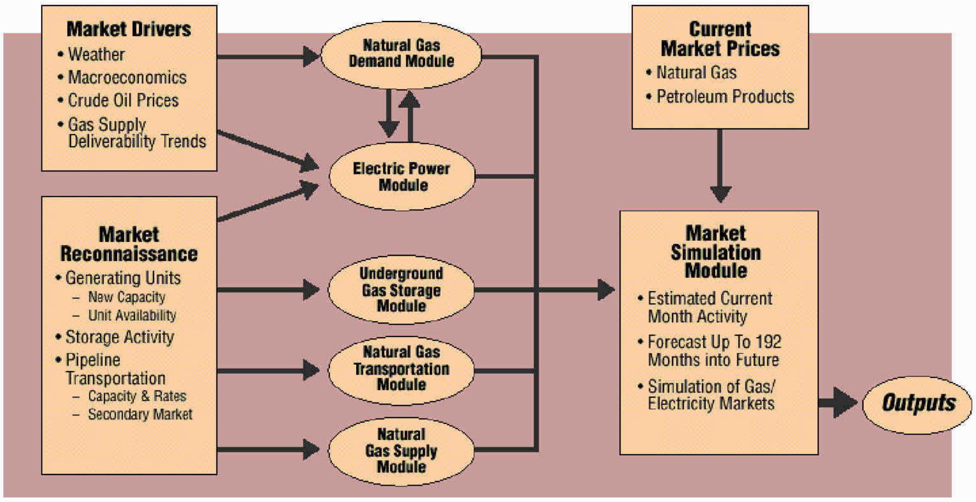
Source: Energy and Environmental Analysis, Inc.



There are nine different components of EEA's model, as shown in Figure 19. The user specifies input for the model in the "drivers" spreadsheet. The user provides assumptions for weather, economic growth, oil prices, and gas supply deliverability, among other variables. EEA's market reconnaissance keeps the model up to date with generating capacity, storage and pipeline expansions, and the impact of regulatory changes in gas transmission. This is important to maintaining model credibility and confidence of results.

Figure 19
GMDFS Structure

Source: Energy and Environmental Analysis, Inc.



The first model routine solves for gas demand across different sectors, given economic growth, weather, and the level of price competition between gas and oil. The second model routine solves the power generation dispatch on a regional basis to determine the amount of gas used in power generation, which is allocated along with end-use gas demand to model nodes. The model nodes are tied together by a series of network links in the gas transportation module. The structure of the transmission network is shown in Figure 20 and the nodes are identified by name in Table 14. The gas supply component of the model solves for node-level natural gas deliverability or supply capability. The Hydrocarbon Supply Model (HSM), as discussed in the next section may be integrated with the GMDFS to solve for deliverability. The last routine in the model solves for gas storage injections and withdrawals at different gas prices. The components of supply (i.e., gas deliverability, storage withdrawals, supplemental gas, LNG imports, and Mexican imports) are balanced against demand (i.e., end-use demand, power generation gas demand, LNG exports, and Mexican exports) at each of the nodes and gas prices are solved for in the market simulation module. A few other charts that summarize input/output and regional breakout for the EEA Model are shown as Figure 21, Figure 22, Figure 23 Figure 24, and Figure 25. The EEA model resides on a MS-Windows PC, and it relies on easy-to-use MS-Excel and MS-Access programs developed by EEA.

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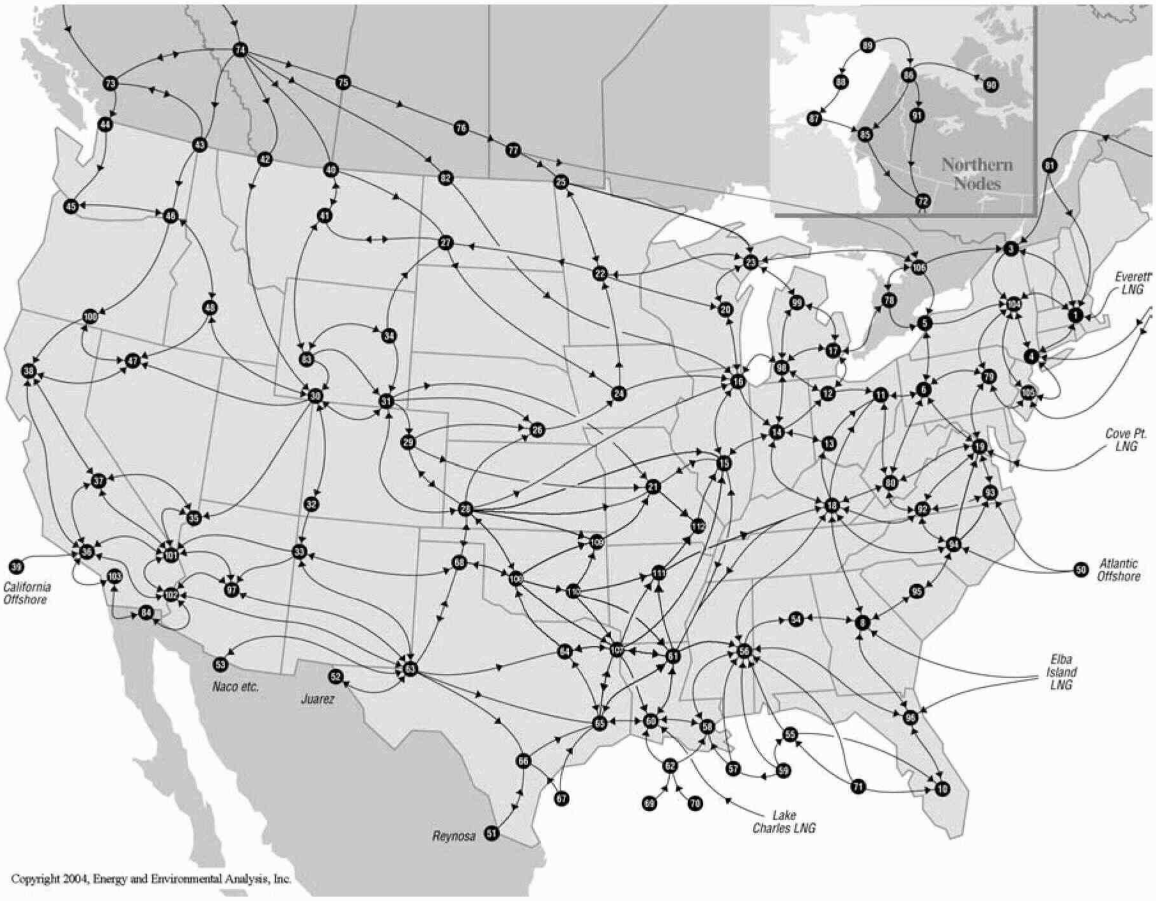
Figure 20
GMDFS Transmission Network

Source: Energy and Environmental Analysis, Inc.



BW000803

Figure 21
Model Drivers

Source: Energy and Environmental Analysis, Inc.

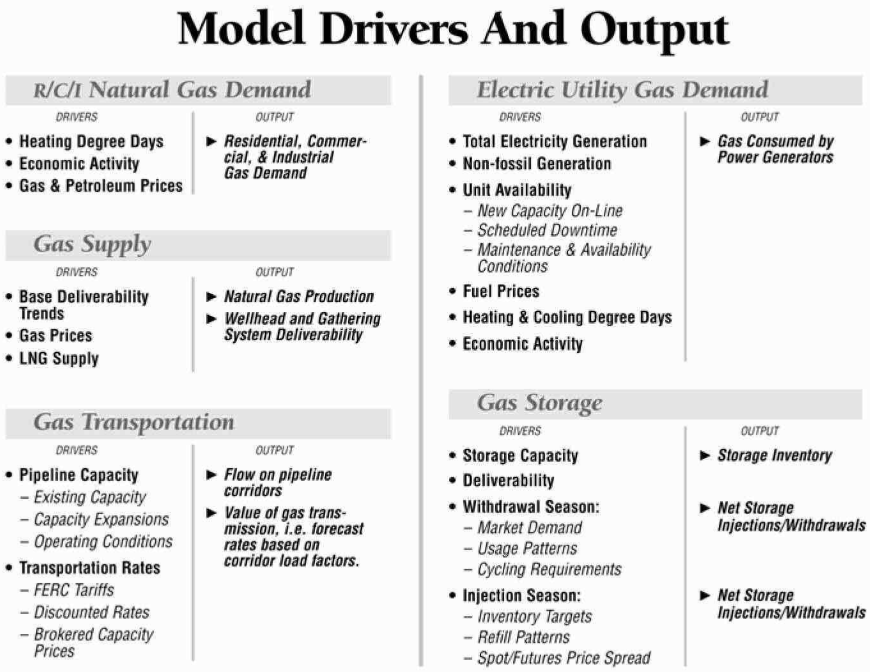


Figure 22
Model Output

Source: Energy and Environmental Analysis, Inc.

Outputs of the Forecasting System

MONTHLY DATA	DATA CONTENT	GEOGRAPHIC DETAIL OF DATA
Gas Pricing	Delivered to Pipeline and Citygate Prices	112 Points
Pipeline Transportation	Inter-Regional Capacity Tariffs Caps Market Value of Capacity	327 Network Corridors
Gas Storage	Working Gas Capacity Inventories Injection/Withdrawal Activity	26 Storage Regions
Natural Gas Demand	By Sector (R/C/I)	34 U.S. and 7 Canada/Alaska Regions
Natural Gas Supply	Deliverability Dry Production Gas Imports/Exports Supplemental Fuels	62 U.S. and 13 Canada/Alaska Regions
Electricity Markets (U.S. Only With Explicity Imports)	Natural Gas Demand Electricity Demand Power Generation Balance Gas-fired Generation	13 "NERC" Regions

Figure 23
Demand Regions

Source: Energy and Environmental Analysis, Inc.

Figure 24
Production Regions

Source: Energy and Environmental Analysis, Inc.

BW000805

Figure 25
Storage Regions

Source: Energy and Environmental Analysis, Inc.

BW000806

Table 14
GMDFS Network Node List

Source: Energy and Environmental Analysis, Inc.

Node	Name	Node	Name
1	New England	57	East Louisiana Shelf
2	Everett LNG	58	Eastern Louisiana Hub
3	Quebec	59	Viosca Knoll/Desoto/Miss Canyon
4	New York City	60	Henry Hub
5	Niagara	61	North Louisiana Hub
6	Leidy	62	Central and West Louisiana Shelf
7	Cove Point LNG	63	Southwest Texas
8	Georgia	64	Dallas/Ft Worth
9	Elba Island LNG	65	East Texas (Katy)
10	South Florida	66	South Texas
11	East Ohio	67	Offshore Texas
12	Maumee/Defiance	68	Northwest Texas
13	Lebanon	69	Garden Banks
14	Indiana	70	Green Canyon
15	South Illinois	71	Eastern Gulf
16	North Illinois	72	North British Columbia
17	Southeast Michigan	73	South British Columbia
18	Tennessee/Kentucky	74	Caroline
19	MD/DC/Northern VA	75	Empress
20	Wisconsin	76	Saskatchewan
21	Northern Missouri	77	Manitoba
22	Minnesota	78	Dawn
23	Crystal Falls	79	Philadelphia
24	Ventura	80	West Virginia
25	Emerson Imports	81	Eastern Canada Demand
26	Nebraska	82	Alliance Border Crossing
27	Great Plains	83	Wind River Basin
28	Kansas	84	California Mexican Exports
29	East Colorado	85	Whitehorse
30	Opal	86	MacKenzie Delta
31	Cheyenne	87	South Alaska
32	San Juan Basin	88	Central Alaska
33	EPNG/TW	89	North Alaska
34	North Wyoming	90	Arctic
35	South Nevada	91	Norman Wells
36	SOCAL Area	92	Southwest Virginia
37	Enhanced Oil Recovery Region	93	Southeast Virginia
38	PGE Area	94	North Carolina
39	Pacific Offshore	95	South Carolina
40	Monchy Imports	96	North Florida
41	Montana/North Dakota	97	Arizona
42	Wild Horse Imports	98	Southwest Michigan
43	Kingsgate Imports	99	Northern Michigan
44	Huntingdon Imports	100	Malin Interchange
45	Pacific Northwest	101	Topock Interchange
46	NPC/PGT Hub	102	Ehrenberg Interchange
47	North Nevada	103	SDG&E Demand
48	Idaho	104	Eastern New York
49	Eastern Canada Offshore	105	New Jersey
50	Atlantic Offshore	106	Toronto
51	Reynosa Imp/Exp	107	Carthage
52	Juarez Imp/Exp	108	Southwest Oklahoma
53	Naco Imp/Exp	109	Northeast Oklahoma
54	North Alabama	110	Southeastern Oklahoma
55	Alabama Offshore	111	Northern Arkansas
56	Mississippi/South Alabama	112	Southeast Missouri

APPENDIX B

AMERICAN BUREAU OF SHIPPING, APPROVAL IN PRINCIPLE LETTER TO BROADWATER ENERGY, DATED JULY 27, 2005

ABS
AMERICAS DIVISION

27 July 2005

Mr. David Carpenter
Technical Manager
Shell Trading (US) Company
Two Shell Plaza
777 Walker, Room 2258
Houston, TX 77002

Ref: Program Class- Approval in Principle for Broadwater –FSRU

Dear David:

ABS has received documentation for the Floating Storage Regas Unit on 18 March and 7 July 2005; this information is:

1- Broadwater LNG PROJECT – Floating Storage & Regasification Unit Basis of Design Part A and Part B dated February 2005
2- Broadwater Resource Report No 13 dated August 2005 (draft)

This has been provided for review in accordance with ABS proposed work scope by ABS in "ABS Proposal for Approval in Principle (AIP) dated March 2005". All elements requested for review are in the proposed work scope. Key elements to be evaluated for the FSRU concept are:

1) Hull and containment system –366.36X 60 X 27 M with membrane tanks
2) Yoke mooring system
3) Loading from the LNG Carrier
4) Topsides Vaporization Plant
5) Conventional Marine Systems
6) Accommodations
7) Send out 1.25 bcf/d
8) HAZID, HAZOP and other special studies.

Whilst the concept of combining a floating re-gasification unit and distribution network with a yoke moored LNG hull can be viewed as a first time combination of systems, the technologies employed are not in themselves novel and are covered by established Rule criteria.

The documents provided illustrate that the concept will:

1- Utilize the hull and cargo tanks that comply with the IGC Code and ABS Rules
2- Yoke mooring system will comply with conventional practice
3- Loading from the LNG Carrier will use conventional systems but be at Broadwater site
4- Topsides will use components in use on shore
5- ABS- Guidance Notes on Review and Approval of Novel Concepts dated June 2003 is being followed
6- Initial Risk Studies have been done and a HAZID Register is being maintained

ABS PLAZA, 16855 NORTHCHASE DRIVE, HOUSTON, TX 77060-6008 USA
TEL: 1-281-877-6000 FAX: 1-281-877-6001 EMAIL: abs-amer@eagle.org

AMERICAS DIVISION

7- Additional Studies will be done as the design develops.

ABS review of the above documentation for Class- AIP for the FSRU is subject to the following:

1. The FSRU is to comply with the IGC Code and ABS Rules as well as those where the Unit is located. Kindly refer to the Annex 2 of Part 5 Chapter 8 of the Steel Vessel Rules for additional requirements for operation in US waters.

2. During final design for the FSRU details are to comply with ABS Rules and Guides for:

   - **ABS Rules for Building and Classing Steel Vessels– 2003**
   - **ABS Rules for Building and Classing Single Point Moorings – 1996**
   - **ABS Guide for Building and Classing Floating Production Installations – June 2000**
   - **ABS Guide for Building and Classing Facilities on Offshore Installations – June 2000**
   - **ABS Guide for Building and Classing Offshore LNG Terminals – December 2002**
   - **ABS Guidance Notes on Risk Assessment Application for the Marine and Offshore Oil and Gas Industries – June 2000**
   - **ABS Guide for Risk Evaluations for the Classification of Marine-Related Facilities**
   - **ABS Guidance Notes on Review and Approval of Novel Concepts – June 2003**.

3. HAZARD Register is to be maintained to confirm that any necessary mitigation provided will satisfy the intent of the International Maritime Organization (IMO) Formal Safety Assessment Guidelines, the tenets of the International Gas Code, and ABS Rules and Guides. This is to include hazards identified by current studies and those requested.

   You may also refer to *ABS Guidance Notes on Alternative Design and Arrangements for Fire Safety*. This would be useful in establishing the suitability of alternatives that may be found necessary for the FSRU.

The FSRU could be classed in accordance with ABS Rules and other requirements identified in the class –AIP and receive a class certificate when built. ABS notes that the concept has been discussed with FERC and USCG to assure that any special concerns that they may have are properly evaluated and incorporated in the final design.

Regards,

for Kenny Patel

Philip G. Rynn
Senior Staff Consultant

cc: K. Richardson, B. Lind, P. Rynn, H. Patel

APPENDIX C

STRATFORD SHOAL CONTINGENCY PLAN

C3.1 Introduction

The preferred method of lowering the connecting pipeline is one or more passes of a post-lay plow. The plow will excavate a trench below the previously lowered pipeline, and the pipeline will be lowered into the furrow as the plow is pulled ahead by the laybarge or vessel.

Broadwater completed a geophysical survey and geotechnical sampling and testing program to characterize the sediments along the proposed pipeline route within the pipeline trench depth. The results are presented in Resource Report No. 7 (Soils). In general, it was observed that the soils are mostly fine-grained silts, clays, and sands for over 95% of the route, with coarser material (gravel and cobbles) occurring at Stratford Shoal (*see* Figure C3-1).

The geophysical survey conducted across Stratford Shoal confirmed the presence of hard material; however, the instrumentation was unable to identify whether the material was solid rock, cobbles, pebbles, or boulders. The geotechnical sampling conducted across the area (*see* Figure C3-2) used a vibrating core barrel or probe to penetrate below the seabed to a depth suitable to allow the lowering of the pipeline. Still photographs identified the seabed as being comprised of 3- to 4-inch cobbles, and the probe successfully penetrated deeper than 4 feet at all locations at which the likely absence of harder materials not suitable for plowing was indicated. However, the results are not considered conclusive, and further investigations will be needed during the detailed pipeline design phase.

C3.2 Test Plow Investigation

During the detailed pipeline design phase, further investigations will be required to confirm that the materials discovered during the 2005 marine survey are consistent across Stratford Shoal. Completion of this program will be required before Broadwater can accept post-lay plowing as the definite pipeline installation and lowering method across Stratford Shoal.

The test plow investigation will involve using a scaled-down plow to physically evaluate the soils that are between the 2005 vibracore sites. The test plow investigation will likely be completed at some point during the October 2008 through April 2009 period.

The test plow investigation will be conducted by independent, experienced pipeline lowering engineers who will develop and design the test program, provide supervision during the test plow investigation, and evaluate the results. Subject to availability, an existing cable-lowering plow may be utilized. The alternative is to design and fabricate a test plow.

If post-lay plowing across Stratford Shoal is rejected as a result of this investigation, then detailed planning for pre-lay trenching will be initiated, including discussions with suitable dredging contractors.

C3.2 Pre-Lay Trenching

The water depth across Stratford Shoal provides a challenge for pre-lay trenching. The most controlled method of trenching would be to use a long-arm excavator unit. This is a specialized spud barge containing a heavy duty excavator. Another option is to use a clamshell dredge; however, its effectiveness and accuracy in deep water is reduced.

Based on current geotechnical survey results, the potential pre-lay trenching length may be as long as 4,000 feet. Water depths through this section are less than 80 feet, which would permit the use of a spud-moored backhoe dredge of the type represented in Figure C3-3. The expected rate of production would be between 3,000 and 5,000 cubic yards per day, assuming a 40-foot box cut (*see* Figure C3-4). The side slopes with this material should slump to leave a 2:1 side slope and an approximate bottom width of 26 feet on which to install the pipeline. The trench volume would be approximately 40,000 cubic yards, compared to 11,700 cubic yards for the post-lay plow method. It is expected that the trench spoil would be recovered to a hopper barge and then dumped at an existing dumping site in Long Island Sound. The test plow results will be evaluated to determine whether the pre-lay trenching length and associated excavation volume can be reduced.

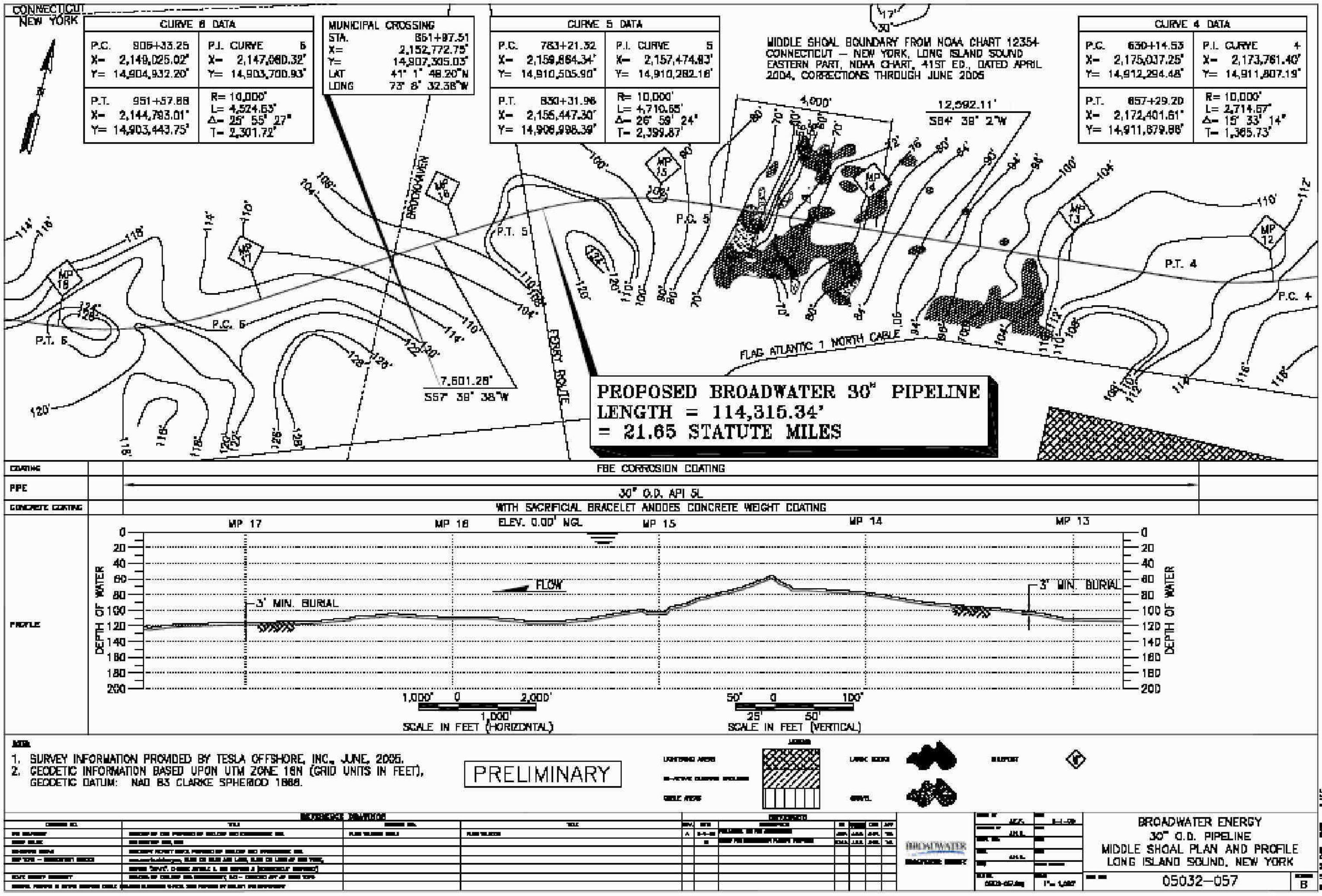
Pre-lay trenching operations would be initiated early in the pipeline construction schedule in October 2009. Trenching activities would span approximately 20 days, including an assumed 33% weather downtime factor; this does not include mobilization and demobilization. The equipment spread would comprise a backhoe dredge (with dive support), support tugs, survey launch, and two hopper barges with dump chutes.

C3.3 Pipe Lay

The entire 21.7-mile-long connecting pipeline will be installed utilizing a purpose-built pipeline laybarge or vessel using an installation method known as S-Lay. An average lay rate of 100 joints per 24-hour day, working around the clock in shifts, is anticipated, with a 25% weather and/or mechanical downtime factor.

The pipeline will be laid as one continuous operation, including the sections to be lowered by post-lay plow across Stratford Shoal. The pre-trench width of 26 feet through Stratford Shoal is sufficient room to ensure that installation of the pipeline in the bottom of the pre-excavated trench is achieved.

Figure C3-1 Middle Ground Plan and Profile



C-4

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Figure C3-2 Middle Ground Potential Dredge Area

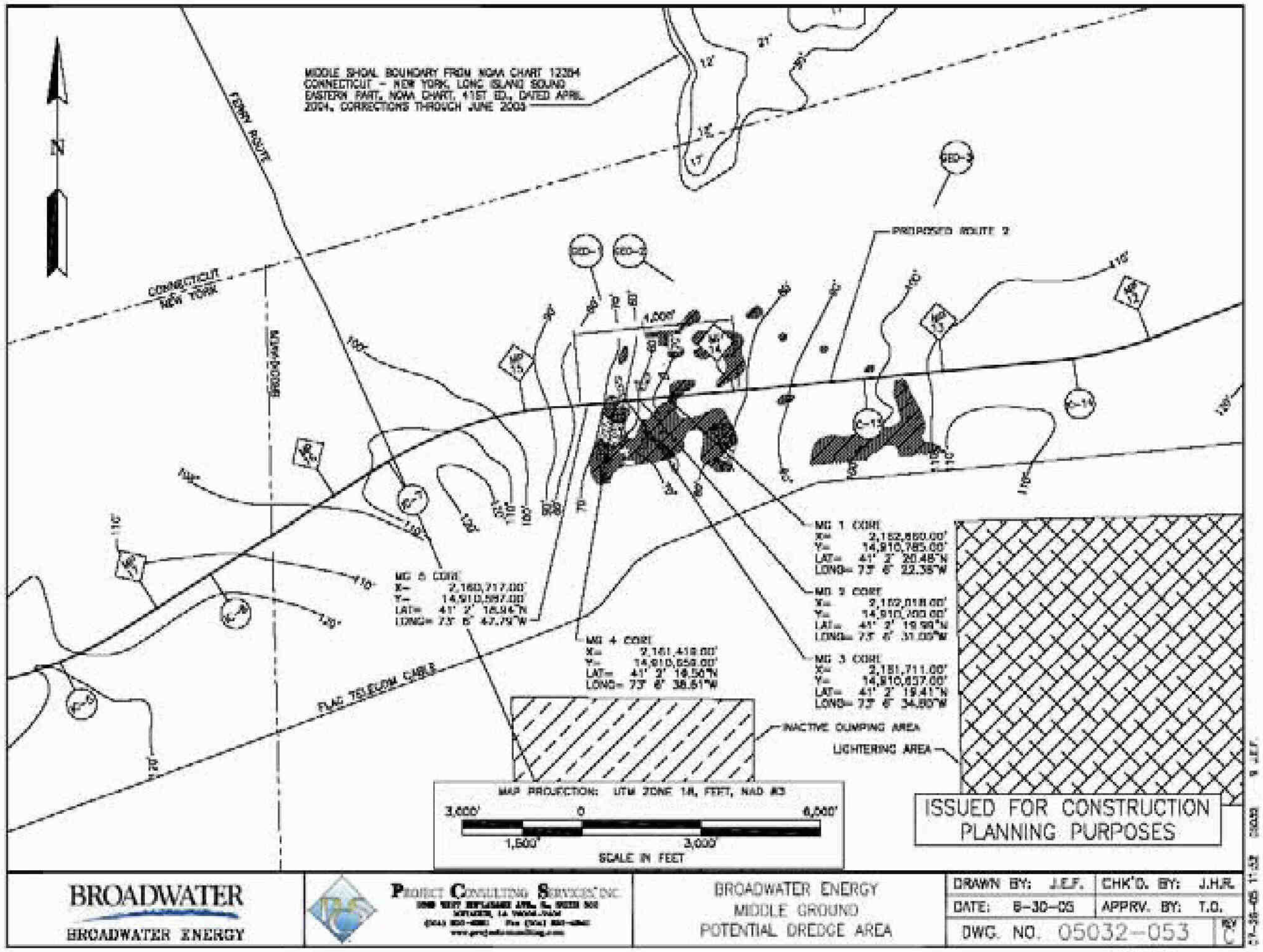

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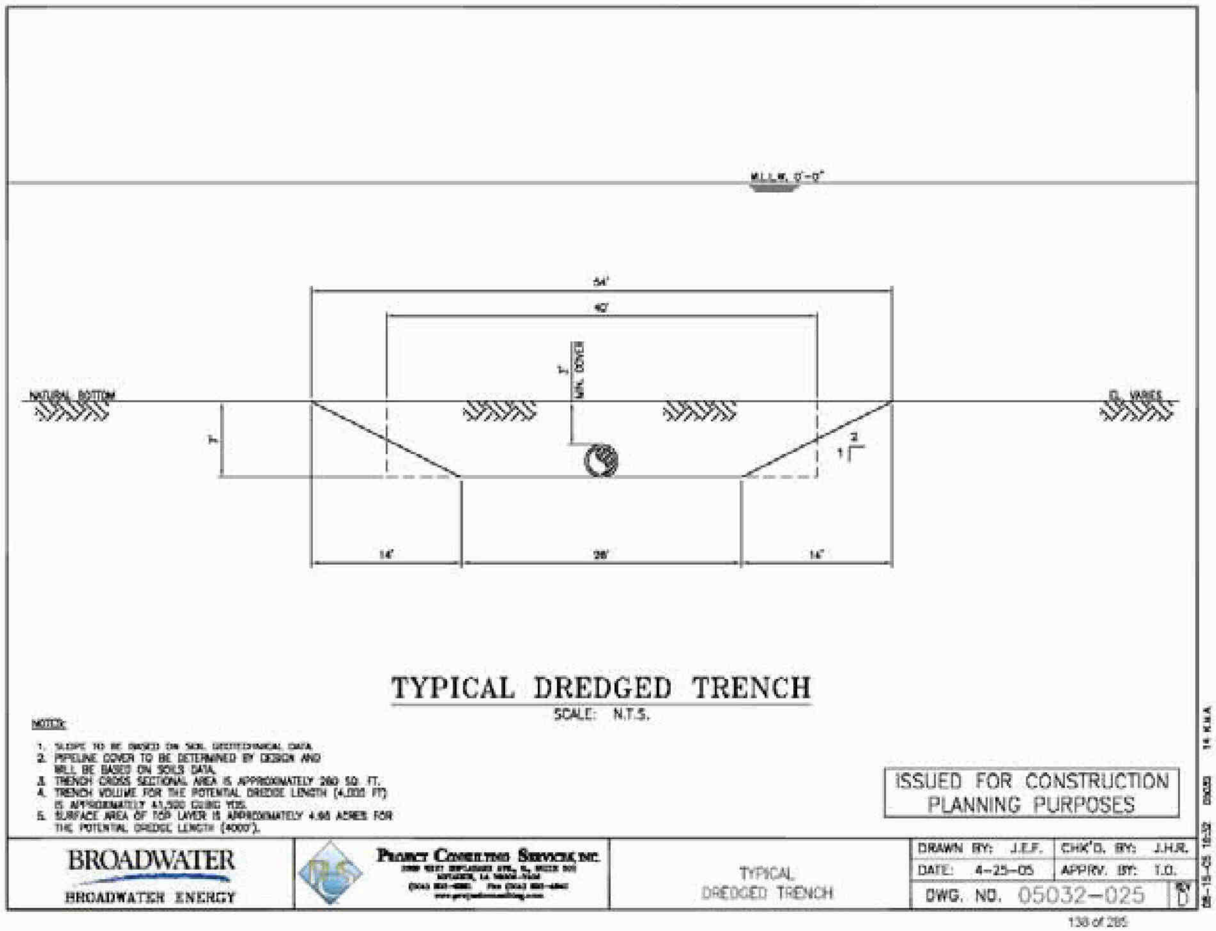
Figure C3-3 Representative Backhoe Dredge

Source: Great Lake Dredge and Dock Web site (www.gldd.com)

Figure C3-4 Typical Dredged Trench



C3.4 Environmental Impacts

Dredging of Stratford Shoal would result in greater turbidity and sedimentation than would be expected from use of the preferred subsea plow. A turbidity plume would be expected to develop during dredging, with incidental release of the sediment occurring as the excavator or clamshell dredge brings the material up to the hopper barge for subsequent disposal. While the greatest turbidity would occur at the bottom during excavation of the sediment, some turbidity would be exhibited on the surface due to the proposed disposal method. Based on the anticipated progress of the dredging activities (3,000 to 5,000 cubic yards per day) the duration of actual dredging would be approximately 13 days, assuming minimum progress. Broadwater's anticipated schedule of 20 days includes a 25% contingency for weather, or other, delays. Since Stratford Shoal is primarily comprised of sand, gravel, and cobbles, the particles in the plume would settle out rapidly, resulting in only minimal transport of sediment. Any significant deposition of the sediment is expected to be restricted to the central pipeline corridor. The lack of contamination identified during the laboratory analysis of sediment samples collected during the spring 2005 field survey minimizes potential impacts associated with the distribution of contamination in conjunction with dredging activities.

Short-term impacts on the existing biological communities on Stratford Shoal would be expected. More mobile organisms would be expected to avoid the dredging activities, while some limited mortality would be expected for less mobile organisms located in immediate proximity to the trench line. Turbidity-related impacts are expected to be minimal, and the turbidity would quickly dissipate following cessation of dredging activities, as the suspended materials would be quickly assimilated through the natural tidal fluctuations experienced daily in Long Island Sound. While the Stratford Shoal area is significantly shallower than the remainder of the proposed pipeline route, no significant or unique communities were identified within the Project area, nor is the area used to a greater extent by the commercial fishing industry. While the on-water boating survey (*see* Appendix B to Resource Report 8 – Land Use, Recreation, and Aesthetics) indicates a higher usage of the Stratford Shoal for recreational fishing, proposed construction activities would occur in the late fall or winter, outside the period of highest use of the Sound.

Due to the short-term nature of the proposed dredging activities, coupled with the sediment composition of Stratford Shoal, the impacts on water quality and existing ecological communities are not expected to be significant if dredging activities at Stratford Shoal are required.